

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

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P.D. HAMILTON, Individually and as
Trustee of the Prentice Dell Hamilton and
Florine Hamilton Family Trust

VS.

CIVIL ACTION NO. 9:01CV132

KOCH INDUSTRIES, INC., Individually
and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
GS PIPELINE COMPANY, L.L.C.,
ENTERGY-KOCH, L.P., and
EKLP, L.L.C.

**PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS**

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CIVIL ACTION NO. 9:01CV132

KOCH INDUSTRIES, INC., Individually and d/b/a KOCH HYDROCARBON COMPANY, KOCH PIPELINE COMPANY, L.P., KOCH PIPELINE COMPANY, L.L.C., GULF SOUTH PIPELINE COMPANY, L.P., GS PIPELINE COMPANY, L.L.C., ENTERGY-KOCH, L.P., and EKLP, L.L.C.

I.

BASIS OF SUIT AND FACTS IN SUPPORT

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action in an appropriate district court of the United States for an injunction against another person . . . for a violation of this chapter or a regulation prescribed or order issued under this chapter." 49 U.S.C. § 60121(a)(1). *App. Vol. 1, Tab 1.*¹ The Pipeline Safety Act provides for the prescription and enforcement of minimum federal safety standards for the transportation by pipeline of natural gas, hazardous liquid gas and crude oil. *See, e.g., Natural Gas Pipeline Co. of America v. Railroad Commission of Texas*, 679 F.2d 51, 52 (5th Cir. 1982). The minimum safety standards for interstate pipelines transporting natural gas and hazardous liquids are set forth in 49 C.F.R. Part 192 and 49 C.F.R. Part 195, respectively. *App. Vol. 1, Tabs 2 and 3.*

B. The Parties

P.D. Hamilton ("Hamilton") is the Trustee of the Prentice Dell Hamilton and Florine Hamilton Family Trust which owns property in Trinity County, Texas. *See App. Vol. 1, Tab 4.* The property consists of approximately 420 acres and is used by Hamilton for a commercial cattle operation, including mixed and Semmental-Angus cross bred cattle. *Id.* Hamilton and his family, including his children and grandchildren, also use the property for recreation and hunting. *Id.* Additionally, there is a deer lease on the property and Hamilton leases the property to others for hunting. *Id.* A camp house located on the property is used to sleep overnight. *Id.* The Sterling II pipeline, an interstate pipeline transporting hazardous liquids, crosses Hamilton's property. *Id. Also App. Vol. 1, Tab 5.*

Hamilton is representative of a class of similarly situated individuals and entities who own property through which the Defendants' interstate hazardous liquid and natural gas pipelines run.

¹ All cites are to the Appendix, Volumes 1-5, filed in support of Plaintiff's Response to the Koch Defendants' Motion to Dismiss.

Koch Industries, Inc., individually and doing business as Koch Hydrocarbon Company, Koch Pipeline Company, L.P., and Koch Pipeline Company, L.L.C. own and operate hazardous liquid pipelines in Texas, Oklahoma and Kansas, including the Sterling I, Sterling II and Chaparral pipelines. *App. Vol. 1, Tabs 5, 6, 7, 8 and 9.*

Gulf South Pipeline Company, L.P., GS Pipeline Company, L.L.C., Entergy-Koch, L.P. and EKLP, L.L.C. own and operate approximately 9,000 miles of interstate natural gas pipelines in Texas, Louisiana, Mississippi, Alabama and Florida. *App. Vol. 1, Tabs 10 and 11.* Koch Gateway Company, a wholly-owned subsidiary of Koch Industries, Inc., operated the natural gas pipeline system through 2000 when its name was changed to Gulf South Pipeline Company, L. P. *App. Vol. 1, Tabs 10 and 11.* Gulf South Pipeline Company, L.P. is a wholly-owned subsidiary of Entergy-Koch, L.P. Entergy-Koch, L.P. is a private company formed by Koch Industries, Inc. and Entergy Corporation. *App. Vol. 1, Tab 11.* GS Pipeline Company, L.L.C. is the general partner of Gulf South Pipeline Company, L.P. and EKLP, L.L.C. is the general partner of Entergy-Koch, L.P.

C. The Defendants' Pipelines

Koch's² network of hazardous liquid pipelines is extensive and includes the Chaparral pipeline and the Sterling I and II pipelines. Hazardous liquids transported by Koch include ethane, propane, butane and/or iso-butane. *App. Vol. 1, Tabs 5, 7, 8 and 9.* Koch's hazardous liquid pipeline system transports approximately 100,000 barrels of hazardous liquids per day across the State of Texas. The Chaparral pipeline gathers hazardous liquids from Wyoming, New Mexico, and Texas for delivery to the Texas Gulf Coast. In the State of Texas, the Chaparral pipeline is approximately

² Unless stated otherwise, "Koch" includes Defendants Koch Industries, Inc., Koch Pipeline Company, L.P., Koch Pipeline Company, L.L.C. "Koch" also refers to other Koch entities owned by or related to Koch Industries, Inc.

830 miles long and transverses the Texas counties of Andrews, Bell, Borden, Brazos, Brown, Callahan, Chambers, Comanche, Coryell, Ector, Falls, Fisher, Grimes, Hamilton, Harris, Howard, Liberty, Martin, McLennan, Midland, Milam, Montgomery, Nolan, Robertson, Scurry, Taylor, Winkler and Yoakum. *App. Vol. 1, Tab 8.*

The Sterling I and Sterling II pipelines transport liquid ethane, butane, propane and/or iso-butane from Medford, Oklahoma to Mont Belvieu, Texas. The Sterling I and Sterling II pipelines enter the State of Texas in or near Grayson County, with the Sterling II pipeline continuing through Collin, Fannin, Hunt, Kaufman, Van Zandt, Henderson, Anderson, Houston, Trinity, Polk, San Jacinto, Liberty and Chambers Counties. *App. Vol. 1, Tab 5.* The Sterling I pipeline continues through the Texas counties of Collin, Rockwall, Kaufman, Henderson, Liberty, Nueces, San Jacinto, Walker, Navarro, Freestone, Leon, Madison, Grimes, Chambers, and Montgomery. *App. Vol. 1, Tab 7.* The Sterling I pipeline, built in part in 1929, was taken out of service with the start up of Sterling II in 1993. *App. Vol. 1, Tab 12.* However, within a short time, Sterling I was placed back in service because of an estimated gross profit of 7.6 million dollars per year for the first 15 years from the increased transportation of liquid butane. *Id.* The Sterling I pipeline began operating again in January 1996.

Many of the interstate natural gas pipelines operated by Gulf South³ were purchased in Koch's acquisition of United Gas Pipeline Company in 1992 or 1993. Many of these natural gas lines were very old when purchased, including some lines that were built in the 1920's or 1930's. *App. Vol. 1, Tab 13, Pages 9, 44.* The natural gas pipeline system runs through numerous Texas

³ Unless stated otherwise, "Gulf South" includes Defendants Gulf South Pipeline Company, L.P. and GS Pipeline Company, L.L.C.

counties, including but not limited to Angelina, Trinity, Polk, Van Zandt, Smith, Henderson, Anderson, Cherokee, Houston, Tyler, San Augustine, Nacogdoches, Rusk, and many others. *App. Vol. 1, Tab 10.*

D. Common Operation And Management

Koch Industries is the parent company and controls the operations of the other Koch entities. *App. Vol. 1, Tab 14.* Koch Industries was also the parent company of Koch Gateway Company, the Koch subsidiary responsible for the operation of the interstate natural gas pipelines through 2000. Importantly, the natural gas pipelines are currently being operated in a dangerous condition because of the management and operation of these lines by Koch Gateway Company after their purchase in 1993. *App. Vol. 1, Tab 13, Pages 43-53, 57-58, 86-89. and App. Vol. 1, Tab 14.*

Further, although Koch Gateway Company is now known as Gulf South Pipeline Company, L.P., the natural gas pipeline system is still being managed and operated pursuant to the policies and procedures of Koch. The officers in charge of operations for Gulf South Pipeline Company, L.P. are former officers or employees of Koch Gateway Company, Koch Industries and/or other Koch entities, including President Rolf Gafvert, Senior Vice President John Earley, and Vice Presidents Ed McMullen and Ray Moran. *App. Vol. 1, Tab 15.*

Additionally, the key officers of Entergy-Koch, Gulf South Pipeline Company, L.P.'s parent, are all career Koch employees. Kyle D. Vann, President and CEO of Entergy-Koch, joined Koch Industries in 1979 and has worked as an officer or employee of many Koch entities. *App. Vol. 1, Tab 16.* Dennis J. Albrecht, Executive Vice President and CFO of Entergy-Koch, has worked at Koch Industries for 20 years and "was responsible for the education and implementation of Koch's Market-Based Management® philosophy within Koch Supply and Trading." *Id.* And David A. Sobotka,

President of Entergy-Koch, is the former President of Koch Energy Trading, Inc. *Id.* Likewise, Charles Koch, Koch Industries' Chairman and CEO, Joe Moeller, Koch Industries' President and Chief of Operations, Sam Soliman, Koch Industries' CFO, and Cy Nobles, Senior Vice President for Koch Industries, are on the board of directors that governs Entergy-Koch. *App. Vol. 1, Tab 11.*

Just a few months after beginning operations, Entergy-Koch's President and CEO, Kyle D. Vann, discussed the Gulf South pipeline system, including its strong market position and possible expansion in a presentation to the American Gas Association, Financial Forum. *App. Vol. 1, Tab 17.* Consistent with Koch's Market-Based Management®, Entergy-Koch's President and CEO emphasized that "aggressive cost reductions drive increases in pipeline profitability." *Id.* Operating costs for the Gulf South pipeline system have been reduced by more than 25 percent from 1997 to 2000. *Id.* Although Koch Gateway Company has changed its name to Gulf South Pipeline Company, L.P., the natural gas pipeline system is still being operated pursuant to the Koch philosophy that emphasizes increased profits over pipeline integrity. *Id.; App. Vol. 1, Tab 14; App. Vol. 1, Tab 18.*

E. The Market-Based Management® System

The hazardous liquid and natural gas pipelines are operated and maintained pursuant to a philosophy or strategy created by Charles G. Koch called Market-Based Management®. *App. Vol. 1, Tab 19.* Koch's Market-Based Management® system has benefitted Koch with a consistent record of profitable growth significantly above the industry average. *App. Vol. 1, Tab 20.* In 1997, Charles Koch stated that Market-Based Management® has enabled Koch to grow two hundredfold over the last 30 years, to where if it were public it would rank 21st on the Fortune 500 list. *App. Vol. 1, Tab 21.*

Employees are trained in Market-Based Management®, which requires every decision to be made based upon the economic effect it would have on the companies and whether it would be profitable. *App. Vol. 1, Tab 13, Pages 82-87; App. Vol. 1, Tab 22, Pages 14-16, 20-21 and 34; App. Vol. 1, Tabs 14 and 23.* Employees are directed and required to cut costs to increase profits, including costs essential and necessary to safely maintain and operate the natural gas and hazardous liquid pipelines. *Id.*

Prior to the acquisition of United Gas Pipeline Company, Kenoth E. Whitstine worked for United Gas for over 29 years. *App. Vol. 1, Tab 13, Page 10.* He became an employee of Koch Gateway Company after the acquisition. *Id.* Whitstine was responsible for all aspects of the natural gas pipeline operation in the Goodrich, Texas area. *Id. at Pages 14-15.* With respect to Koch's Market-Based Management® system and the operation of the pipelines, Whitstine testified that profit, not safety, drove all company goals and decisions:

Q: Have you ever heard of market-based management?

A: Oh, yeah.

Q: Tell the jury what your understanding was of market-based management.

A: Well, basically, from my understanding anyway, it worked with how you spent money. And basically, when you spent money, whatever you spent that money on should be a profit-maker and – or contribute to a profit-maker and that money spent should come back and pay for itself within six months and make Koch more money after that, that – Koch believed that any investment they made should bring back at least a minimum of – it was either 30 or 33 percent.

And it – it also included in personnel. It included everything involved in my operation because when we were coming up with salaries for our people that was looked at in the same respect, as it should have been, I guess.

What could you have hired somebody locally to do that job? If you're paying somebody \$12 an hour, could you get it done for six?

And some jobs you could. But a lot of jobs that that individual might have been doing, you couldn't. So –

Q: Where did you learn about market-based management?

A: After I went to Koch.

Q: And how did you learn about it?

A: Went to Wichita and through – we had – I don't know – a several-day seminar thing up there. And then, also had – brought a lot of stuff back. We were given stuff beforehand, also, to read over and – so we would be, I guess, smart enough to ask questions once we got up there, when they were going through it.

Q: Did you get that little book that's got Charles Koch's forward [sic] in it, about market-based management?

A: Oh, I'm sure we did, yeah. We saw a lot of videos and stuff from Mr. Koch.

Q: While you were up there in training, he was in some of the videos?

A: Yes, sir. And sometimes they'd send the videos out in the field to play to the employees.

Q: So, you'd get – you would get videos sent out for the employees to look at about how market-based management worked or what the philosophy was?

A: Yeah. Because they – it really needed to drift all the way down to each individual.

App. Vol. 1, Tab 13, Pages 82-84.

Employees are encouraged not to spend money on pipeline integrity or repair because the cost of such financial expenditures would not be recouped by the Defendants for many years. *App. Vol.*

1, Tab 23; App. Vol. 1, Tab 13, Pages 85-87. Whitstine has explained that:

Q: How did it play in the company's policies in terms of what you observed on how operations were carried out, how maintenance was carried out, and those kinds of things?

A: From my experience, we did very little preventive maintenance. Basically it was the philosophy that if – you know, "If it ain't broke, don't work on it." I would – had been brought up under another philosophy of keeping stuff in good shape so it don't break and leave you stranded.

Q: Did you attribute that little preventive maintenance in some way to market-based management?

A: Yeah, because that didn't – you had to quantify a lot of stuff, and there wasn't ways you could put numbers on certain things.

Q: So, if you couldn't put it – you're saying you had to put it into the formulation or the concept of market-based management in order to get it approved; is that what you mean?

A: Basically, yeah.

Q: And you referred earlier to something about if you couldn't recover your investment within – what did you say, how many days?

A: Six – I think it was six months.

Q: Six months. Then was that – was that one of the concepts that you learned under market-based management, that concept of having to recover your investment?

A: Yes, sir.

Q: When you were at United, what was the United management policy with regard to preventive maintenance?

A: We had an intensive preventive maintenance schedule. We had – in fact, that's what it was called, "preventive maintenance schedule," on almost everything. And basically, it was – if we could foresee something coming down the line that was going to be needing attention, it was basically – part of it was so we could budget money sometime during the year to get this done. And that was one reason why we had to keep an eye on it so close, so we could budget the money for it 'cause it – if it wasn't in the budget, then it was a lot harder to get.

With Koch it was – you didn't have a budget. So, they always just told me to wait until it breaks and then they'll fix it.

Q: Whoever – who told you that? Who gave you that direction?

A: I – I guess Mr. [Ed] McMullen [Assistant Division Manager/Supervisor with Koch Gateway Company and currently Vice President with Gulf South] and Bob O'Hare [Division Manager] or whoever. It was –

Q: People over you?

A: Yes, sir.

App. Vol. 1, Tab 13, Pages 85-87.

Much like the cost-risk analysis exposed in the Pinto cases, Koch employees have been told that it is cheaper to pay a lawsuit or fine than repair the pipelines. *App. Vol. 1, Tab 13, Pages 57-58; App. Vol. 1, Tab 14.* Whitstine testified that during his employment with Koch Gateway Company,

he was unable to make necessary repairs and/or correct dangerous conditions that existed on the natural gas pipeline. For example, Whitstine testified that there were numerous exposed pipelines that posed an immediate danger, including an exposed pipeline that was being driven over by logging trucks. Although Whitstine repeatedly reported these dangerous conditions and regulatory violations to his supervisors, including providing photographs of the exposed pipes, no action was taken to correct these violations. *App. Vol. 1, Tab 13, Pages 43-53*. After finally convincing his supervisor to come out and physically look at some of the exposed pipes, still no corrective action was authorized. Whitstine testified that:

A: I talked with him and I told him that – you know, "Here it is, this is what I'm worried about." And he said that he understood my concerns and that I needed to understand that sometimes economically people are – we should do things in a certain fashion or a certain priority and that was – that money spent on particular things on pipelines that don't make very much money, sometimes is not financially advisable, I guess, or economical because it takes forever, if ever, that that money would ever be recouped from the expenditure that you made and that sometimes you needed just to take that into consideration when you're wanting to spend money on particular things. And then, I asked him that – I said: Well, you know – I said: You know, one of them logging trucks could drive over this line here and it could very possibly drag the Dresser off or something and cause a blow-out and possibly burn, catch on fire, and kill the – whoever might be in the logging truck. And he said that he understood that money spent on certain projects could make a lot more money than on other projects and that they could come back and pay off a lawsuit from an incident and still be money ahead. I don't know if I said that right or not, but it's --

Q: Was that the way he told it to you? That's my question.

A: Basically the way I understood it was that – that if – if I didn't spend money doing a particular job – not that particular one we may be looking at, I'm not sure – but a particular job, that I could take that same money that – say it was going to cost ten or twenty thousand dollars to repair that particular location or maybe even more than that, depending on the location – but some of them were as minor as ten to fifteen thousand dollars – that that money could be invested elsewhere and that money would multiply greatly. And it's – it was

better to take a gamble on something happening later and handle that situation when it arose.

Q: So, did he actually say to you that if there were a lawsuit arising from an incident like you described to him of somebody getting killed or burned that it would be better to pay that than fix the pipeline in some instances?

A: Yes, sir, he said that.

App. Vol. 1, Tab 13, Pages 57-58.

* * * *

Q: Other than that conversation with Mr. O'Hare, where the subject of repairing or bringing up to proper standards that exposed pipe, did you have any others with Mr. McMullen or Mr. O'Hare that you can remember between April and October?

A: Well, that one with O'Hare still. This was during that evaluation I was talking about. He said I needed to either learn or understand one, that it's – let me see if I can phrase this right – that it's a lot more efficient to possibly not do some things and save money and invest it elsewhere, where it will grow, and take a chance on getting caught sometime down the line and paying some kind of fine, which usually didn't amount to very much, and that – that they had a stable full of lawyers at Wichita that handled those situations.

Id. at Page 89.

Virtually all decisions made by the Defendants regarding the maintenance and operation of their natural gas and hazardous liquid pipelines are based upon Market-Based Management®. These decisions include those relating to the detection and prevention of corrosion of their natural gas and hazardous liquid pipelines, as well as the repair and replacement of their pipelines. *App. Vol. 1, Tabs 13, 14, 22 and 23.* Moreover, employee incentives and bonuses are often based on whether the employee has cut costs thereby increasing the Defendants' profits. *Id.* Employees are constantly reminded that profitability is most important. *Id.*

Phillip Dubose, a former division manger, has also testified that pipeline safety and regulatory compliance were sacrificed over profit. Dubose's responsibilities included some of Koch's operations in Louisiana, Mississippi, Alabama and Florida, such as the crude oil lines and Koch Marine. Dubose testified that:

Q: And yet you've told the jury in this case that Koch Industries had no concern about safety around these pipelines. I want to know why you believe that.

A: Because it affected our bottom line, impeded progress.

Q: What do you mean by the bottom line?

A: Profit, profit and loss.

Q: Money?

A: Money.

Q: Greed?

A: Yes.

Q: Was Koch Industries, was their attitude toward making a profit such that they placed profit over human safety?
In your opinion.

A: Yes, yes.

Q: Now, was – did you know Bill Caffey?

A: Yes.

Q: Was that his attitude about profit as the executive vice president or – Executive vice president of Koch Industries?

A: Yes. That came – that came all the way down from the top. Everything was profit driven. Squeeze out the biggest profit you possibly could give them.

Q: Was Koch Industries – if you could, tell us whether or not Koch Industries was more concerned about cutting costs than the safety of human life.

A: Yes.

* * * *

Q: First let me ask you, tell the jury, if you would, what your training was in the area of market-based management when you were with Koch.

A: The market-based management was to cut your costs right down to the bone so you could improve profits. That was the whole thing.

Q: Where did you learn about market-based management?

A: I learned it from – I first heard about it from Mr. Charles Koch.

Q: And how did you learn about it from Mr. Koch?

A: In meetings when he introduced market-based management.

App. Vol. 1, Tab 22, Pages 14-16 and 34.

Q: And tell the jury what information you have about Koch's business practices concerning leaks and spills.

A: Well, everything goes back to cost. If you had a spill or leak, you wanted to get this thing taken care of with the least amount of dollars involved. And so a lot of times if it was out in a remote spot where nobody was around and stuff like that, they'd just take a shovel or something – we're talking about a leak, a pipeline leak now – and just take a spade and just kind of spade it over and turn the – turn the soil over, something like this. Or if there wasn't anybody around we might get a – do a fax, a real fax – fix on this thing. We might set it on fire, you know, and stuff like this.

Now, in the Marine division where we would have spills off of barges and the things would hit the – hit the water, what we'd probably do, there's never anybody around and stuff, we'd probably wheel wash. And what we mean by that, we'd take the tug away from the barge and snug the barge up to the bank and hook up the engines. We had twin screw engines on this boat. And that puts out a tremendous wheel wash. You can't imagine. And we'd just kind of wash that thing on down, down the river, and kind of get it all mixed up and get it on – get it on its way.

Id. at Pages 20-21.

Dubose also testified that it in order to increase profits it was Koch's practice to steal oil, underreport spills and leaks to governmental agencies such as the Coast Guard, not conduct inspections of the pipelines or right-of-ways, steal supplies and materials, and overload trucks that drove across Texas roadways. *Id. at Pages 16-18, 21-22, 24-25, 26-29, 36-40, 42-44, 51-52, 58-59, 68-72, 75-84, 90-91, 93-97, 119-121, 125-128, 142-144, 148, 152 and 154-156.*

Bobby Conner, a former Koch Gateway Company employee, has also testified that maintenance and repair of Koch's pipeline system was sacrificed for increased profits. *App. Vol. 1, Tab 14*. According to Conner, he was repeatedly instructed by Koch management to ignore safety regulations and avoid compliance because it was costing Koch profits. *Id.* Conner was not allowed to conduct inspections, maintenance or repairs of the pipelines if it would require additional manpower or cash expenditures. *Id.* Conner has also testified that his Koch supervisors repeatedly demanded that he sign false Department of Transportation (DOT) inspection and maintenance reports and, when he refused, his employment was terminated. *Id.*

Conner has over 15 years experience in the pipeline industry and recently inspected the natural gas pipeline in East Texas. *Id.* Based on this inspection, Conner has concluded that the lack of maintenance of the natural gas pipeline has become even more serious since his termination in 1997. *Id.*; *App. Vol. 1, Tab 18*. His inspection confirmed that many areas of the pipeline are not properly marked, there are locations along the pipeline that are either exposed or buried at a dangerously shallow depth, many of the right-of-ways are not being maintained and are overgrown, the pipeline and right-of-ways are not being inspected, and at at least two locations he smelled mercaptan where gas was obviously escaping or leaking from the pipeline. *Id.*

The above testimony and additional evidence discussed below, reveals that Defendants' Market-Based Management® system is used to avoid costs, even if such costs are necessary to ensure regulatory compliance and pipeline integrity. The pressure to increase profits comes from the very top with the system's creator, Charles Koch. In a 1996 inter-company memo, Charles Koch calculated that even a ten percent reduction in costs would increase Koch's earnings by \$550 million per year. *App. Vol. 1, Tab 24*. This memo further declares that targets of the campaign to reduce

costs would include "poor economic thinking (especially the failure to connect costs with the creation of value)." *Id.* Even job descriptions for field technicians state that their responsibilities include discovering ideas to lower operating costs, identifying and eliminating waste, limiting overtime, understanding and being "bought into" the Market-Based Management® system, and identifying opportunities to increase net profit value. *App. Vol. 1, Tab 25.*

F. The Defendants' Market-Based Management System Violates Federal Regulations Requiring Policies, Procedures And Training To Ensure Pipeline Integrity

The Pipeline Safety Act, 49 U.S.C. §60101 *et seq.*, and the prescribed regulations implementing such Act, set forth minimum safety standards to ensure pipeline integrity. *See* 49 C.F.R. §§195.400, 192.601, 192.701. *App. Vol. 1, Tabs 2 and 3.* 49 C.F.R. Part 195, applicable to hazardous liquid pipelines, and 49 C.F.R. Part 192, applicable to natural gas pipelines, require an operator to adopt and follow operations, training and maintenance procedures to ensure pipeline safety. Pipeline operators are also required to have operating procedures and training programs that ensure enforcement of the federal regulations. *Id.* at 49 C.F.R. §§195.402, 195.403, 192.602, 192.603, 192.703. The federal regulations set forth specific procedures related to the inspection of pipelines and right-of-ways, corrosion control, coverage or depth of pipes, adequacy of cathodic protection, dissemination of public information, and other requirements to prevent and correct hazardous pipeline conditions. *Id.*

Contrary to these regulations, the Defendants' Market-Based Management® system is designed to avoid or delay financial expenditures and increase profits, regardless of pipeline safety and regulatory compliance. *App. Vol. 2, Tab 26; App. Vol. 1, Tab 23.* The Defendants' Market-Based Management® system is contrary to the operations, maintenance and training procedures

required by the federal regulations, as well as the specific regulations related to the inspection of pipelines and right-of-ways, corrosion control, coverage or depth of pipes, adequacy of cathodic protection, dissemination of public information, and other requirements to prevent and correct hazardous pipeline conditions. *App. Vol. 2, Tab 26.*

The hazardous liquid pipelines, including the Sterling II pipeline that crosses Hamilton's property, have been and are continuing to be operated in violation of 49 C.F.R. §195.401(a) providing that no operator may operate or maintain its pipeline systems at a level of safety lower than that required by Subpart F and the procedures it is required to establish under §195.402(a);⁴ 49 C.F.R. §195.402 providing that an operator shall have and follow procedures for operating, maintaining and repairing the pipeline system in accordance with each requirement of Subpart F, minimizing the potential for hazards and accidents, and reviewing the work done by personnel to determine the effectiveness of the procedures used in normal operation and maintenance and take corrective action where deficiencies are found; and 49 C.F.R. §195.403 providing that each operator shall train its employees to carry out the safety standards set forth in Subpart F, to recognize conditions that are likely to cause emergencies and take appropriate corrective action, and train its employees to take steps necessary to control any accidental release of hazardous liquids to minimize the potential for injury or environmental damage. *Id.*

Similarly, the natural gas pipelines have been and are continuing to be operated in violation of 49 C.F.R. §192.603 and §192.703 providing that no operator may operate its pipeline unless it is

⁴ 49 C.F.R. Part 195, Subpart F - Operation and Maintenance - sets forth the minimum safety standards to be followed in the operation and maintenance of hazardous liquid pipelines, including but not limited to safety standards related to operating procedures, training, safety-related conditions, corrosion control, inspections, adequate cathodic protection, pipeline repairs, pipeline markers, and public education.

operated and maintained in accordance with the requirements set forth in Subparts L and M;⁵ and 49 C.F.R. §192.605 providing that an operator shall have and follow procedures for operating and maintaining the pipeline system in accordance with each requirement of Subparts L and M, to control corrosion, and to review the work done by personnel to determine the effectiveness of the procedures used in operation and maintenance and take corrective action where deficiencies are found. *Id.*

G. Additional Regulatory Violations

In addition to the foregoing, the Sterling II pipeline that crosses Hamilton's property has been and is continuing to be operated in violation of 49 C.F.R. §195.401(b) providing that when an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time or if the condition presents an immediate hazard to persons or property, the operator must halt operation of the affected part of the system until it has corrected the unsafe condition. In several locations on Hamilton's property, the Sterling II pipeline is less than 30 inches below ground constituting a safety-related condition and violation of 49 C.F.R. §195.401. 49 C.F.R. §§195.248, 195.401(b). *App. Vol. 2, Tab 26.* Further, near and parallel to the Sterling II line, Koch is also operating a natural gas pipeline through Hamilton's property that in some locations is buried as shallow as 8 inches below ground. The shallow depth of this natural gas pipeline poses a very dangerous condition and immediate hazard to the operation of both the natural gas pipeline and Sterling II pipeline. 49 C.F.R. §§192.327, 195.401(b). *App. Vol. 2, Tab 26.*

Additionally, the Sterling II pipeline has been and is continuing to be operated in violation of 49 C.F.R. §195.410 and 49 C.F.R. §195.401(b), in that Koch has failed to place and maintain line

⁵ 49 C.F.R. Part 192, Subparts L and M, set forth the minimum safety standards to be followed in the operation and maintenance of natural gas pipelines.

markers so that the location of the Sterling II pipeline is accurately known. *Id.* Koch has also violated and is continuing to violate 49 C.F.R. §195.440 in failing to provide Hamilton with appropriate public education. The only information Hamilton recalls receiving from Koch regarding a pipeline and/or any emergency resulting from a pipeline is a calendar that he received approximately three years ago. *App. Vol. 1, Tab 4; App. Vol. 2, Tab 26.*

Hamilton believes that the Sterling II pipeline has been and is continuing to be operated in violation of numerous other regulations including 49 C.F.R. §195.412 - failing to inspect the pipeline right-of-way; 49 C.F.R. §195.414 - failing to maintain adequate cathodic protection; 49 C.F.R. §195.416 - failing to monitor, control and correct external corrosion; 49 C.F.R. §195.418 - failing to monitor, control and correct internal corrosion; and 49 C.F.R. §195.422 - failing to make necessary pipeline repairs and maintenance. *App. Vol. 2, Tab 26; App. Vol. 1, Tabs 14 and 18.* However, because the pipeline is buried beneath the ground and Hamilton is not allowed to dig up the pipeline at this time to conduct a visual inspection, and Koch has in its possession all documents and records relevant to the maintenance and condition of the Sterling II pipeline, it is impossible for Hamilton to provide all facts substantiating further violations. Accordingly, Hamilton should be allowed discovery to determine the condition and maintenance history of the Sterling II pipeline, as well as the natural gas pipeline that runs near and parallel to the Sterling II line.

H. History And Record Of Safety Violations And Incidents

Koch's strict adherence to Market-Based Management® in the operation and maintenance of its pipelines and facilities has resulted in a well-documented history of safety violations and lack of regulatory compliance. *App. Vol. 1, Tab 23; App. Vol. 2, Tab 26.* Consistent in Koch's policy and practice of Market-Based Management® is that increased profits are more important than the

integrity of its pipelines and facilities, regardless of whether unsafe conditions may result in injuries, death and/or environmental harm. *Id.*

Koch's Market-Based Management® strategy has constituted a willful and coordinated decision to disregard federal and state regulatory requirements and to court criminal misbehavior. As a direct result of the deliberate decisions of Koch management, individual citizens, entire communities, and the environment have been put at risk for grave hazards. Much as the Defendants may seek to portray this action as an isolated, idiosyncratic complaint, the facts are quite to the contrary. Indeed, the following establishes the persistent violations of governing law by Koch. Further, the persistent practices reinforce the need for the relief sought in this action.

Koch's pipelines have been and are continuing to be operated pursuant to Market-Based Management®. As such, these pipelines, like Koch's other pipelines and facilities, have not been properly maintained or operated safely to ensure increased profits. In short, Koch's operational record is telling. *App. Vol. 1, Tab 23; App. Vol. 2, Tab 26.*

1. Kaufman County Explosion and Resulting Deaths

On August 24, 1996, Koch's Sterling I pipeline ruptured allowing 400,000 gallons of liquid butane to escape and form a butane vapor cloud in the residential area of Oak Circle Estates in Kaufman County, Texas. *App. Vol. 2, Tab 27; App. Vol. 2, Tab 28, Pages 55-56.* Danielle Smalley and Jason Stone died as a result of the fire and explosion. Numerous Texas residents who owned property in the surrounding area also sustained substantial property damage as a result of the fire and explosion. *App. Vol. 2, Tab 27.*

The Kaufman County disaster was the result of the corroded condition of the Sterling I pipeline. *App. Vol. 2, Tab 27.* A metal pipeline is protected from corrosion by two methods, coating

and cathodic protection. *App. Vol. 2, Tab 29, V. 5 - Pages 223-224*. Pipeline operators are required by the Pipeline Safety Act and the federal regulations to maintain adequate cathodic protection. *Id. at V. 5 - Page 229; App. Vol. 1, Tab 3*. Pipe-to-soil readings are taken to ensure that the pipeline operator's cathodic protection system is working properly and effectively protecting the pipe from corrosion. The minimum industry standard and Koch's own standard of protection require a current of at least .85 volts flowing toward the pipe. *App. Vol. 2, Tab 29, V. 5 - Pages 227-228*.

Prior to the Kaufman County explosion, Koch knew the Sterling I pipeline was improperly laid in the rain and that there were coating problems. *Id. at V. 7 - Page 21*. The first annual survey of the pipeline in 1982 recorded low cathodic protection levels below the minimum .85 volts. *Id. at V. 5 - Pages 237, 239-240*. Subsequent readings of low cathodic protection near the rupture site were recorded in 1984 and 1985. *Id. at V. 5 - Page 240*.

Throughout the mid to late 1980s, there were several instances in which digs were made near the rupture site and disbonded or damaged coating was observed and documented by Koch. *Id. at V. 5 - Pages 240-241*. In 1990, Koch conducted six random digs in Kaufman County to inspect the Sterling I pipeline. At all six locations or sections of the pipeline, Koch found coating that was disbonded and not protecting the pipe. *App. Vol. 2, Tab 30*. In 1991, the corrosion supervisor for Sterling I reported to Koch that the coating on the Sterling I pipeline near the rupture site was aged and deteriorating and that a greater increase in the current or cathodic protection requirement should be expected. *App. Vol. 2, Tab 31, Pages 236-239*. In 1991, Koch was also aware that the M8 rectifier, near the rupture site, was down and not providing cathodic protection. *App. Vol. 2, Tab 29, V. 5 - Pages 246-247*.

The Sterling I pipeline was taken out of service in 1993. Around 1994, Koch decided to place Sterling I back in operation and estimated a gross profit of 7.6 million dollars per year for the first 15 years from the increased transportation of liquid butane. *App. Vol. 1, Tab 12*. The Sterling I pipeline actually began operating again in January 1996. However, prior to reopening the pipeline, Koch knew that the condition of the pipeline at and near the rupture site in Kaufman County, Texas was dangerous. Koch knew there was disbonded and damaged coating, that the cathodic protection system was dying, and that the pipe was corroded. *App. Vol. 2, Tab 32, Pages 168-171; App. Vol. 2 Tab 33, Pages 99-100*.

In March 1995, Koch knew the M-9 rectifier, the closest rectifier to the Kaufman County, Texas rupture site, was being depleted and that the ground bed was being used up and would soon be useless. In April 1995, Koch conducted a hydrostatic test that failed. The first hydrostatic test failed because the pipe burst in Kaufman County as a result of corrosion. *App. Vol. 2, Tab 29, V. 5 - Pages 251-253; App. Vol. 2, Tab 31, Page 240*.

In May 1995, Koch conducted a low-resolution smart pig test to determine the overall condition of the Sterling I pipeline. *App. Vol. 2, Tab 29, V. 5 - Page 254*. A smart pig is an electronic device that it pumped through the pipe to take readings from inside of the pipeline and provides data regarding the condition or integrity of the pipeline, including wall thickness and corrosion of the pipeline. *Id. at V. 5, Page 230*. The low-resolution smart pig test identified 583 defects in the Sterling I pipeline with 15 percent or greater loss of wall thickness. *Id. at V. 5 - Pages 254-255*. By industry standards, the Sterling I pipeline was described as being like swiss cheese. *Id. at V. 5 - Page 257*. Koch only attempted to repair 80 of the 583 defects, limiting the repairs to

those corrosion defects identified as moderate (30 percent to 50 percent loss of wall thickness) and severe (greater than 50 percent loss of wall thickness). *App. Vol. 2, Tab 29, Page 255.*

During the digs to conduct the limited repairs of the Sterling I pipeline, Koch also found corrosion, disbonded coating and low cathodic protection readings on the pipeline. *App. Vol. 2, Tab 34, Page 52; App. Vol. 2, Tab 33, Pages 99-100.* The M-9 rectifier, the closest rectifier to the rupture site, was down in September 1995. *App. Vol. 2, Tab 32, Pages 159-160; App. Vol. 2, Tabs 27 and 35.* In February 1996, Koch knew that its cathodic protection system near the rupture site was dying and decided to add a rectifier and ground bed to be designated as M-8.5. *App. Vol. 2, Tab 36.* Koch also knew it needed to replace the ground bed at M-9 because it was depleted. *App. Vol. 2, Tab 37, Page 136.* Koch continued to be aware that the M-9 rectifier was down and not protecting the pipeline near the rupture site in March 1996, May 1996 and July 1996. *App. Vol. 2, Tab 32, Pages 181-182; App. Vol. 2, Tab 36.*

Although Koch knew the Sterling I pipeline near the rupture site was not being protected, it failed to add a rectifier and ground bed at M-8.5 or replace the ground bed at M-9 prior to the explosion because of the cost of doing so. *App. Vol. 2, Tab 38, Pages 42-44.* Indeed, Koch was aware of the dangerous condition of the Sterling I pipeline near the rupture site for at least twelve to fifteen months prior to the explosion, but still continued to operate the pipeline at maximum operating pressure. *App. Vol. 2, Tab 32, Pages 168-171; Vol. 2, Tab 39, Trial Testimony-Page 164.*

The rupture of the Sterling I pipeline was 12.5 inches long, with an area of corrosion at least 5 inches long by 3 inches wide. In the rupture area, corrosion pits substantially penetrated the pipe wall indicating nearly 100 percent wall thickness loss. *App. Vol. 2, Tab 27.* Although coating on the section of the pipeline which ruptured was destroyed by the fire, an inspection of several sections

of the pipe extracted near the rupture site all revealed disbonded, cracked and damaged tape coating. *Id.* Less than ten days after the explosion, Koch added a rectifier at M-8.6 (previously designated as M-8.5) and replaced the ground bed at M-9. *Id.* The estimated cost of the new rectifier was \$13,000. *App. Vol. 2, Tab 40.*

The National Transportation Safety Board ("NTSB") concluded that the probable cause of the explosion in Kaufman County, Texas was the failure of Koch to adequately protect its pipeline from corrosion. *App. Vol. 2, Tab 27.* Findings of the NTSB included the following: (a) inadequate corrosion protection at the rupture site and at numerous other locations on the pipeline allowed active corrosion to occur before the accident; (b) because cathodic protection levels were inadequate, the stress cracks that existed in the coating created areas in which rapid corrosion could occur; (c) disbonded tape coating most likely created locally shielded areas on the pipe that prevented adequate cathodic protection current from reaching its surface, creating other areas in which rapid corrosion could occur; (d) although Koch's records contained information that cathodic protection levels were inadequate and that active corrosion was occurring on its pipeline system before the accident, the conditions went uncorrected; (e) the tape coating on Koch's entire pipeline may have tape cracking and disbondment; (f) the format and content of the public education bulletin mailed by Koch did not effectively convey important safety information to the public; and (g) Koch's distribution program for its public education materials was inadequate. *Id.* The NTSB also recommended that Koch evaluate the integrity of the remainder of the Sterling I pipeline, including the condition of the tape coating on the entire Sterling I pipeline, and make such repairs of the pipeline as necessary. *Id.*

Bill Caffey, the number three man at Koch Industries, Inc. at that time, received a 1996 bonus of \$900,000 for his performance. *App. Vol. 2, Tab 39, Pages 304-307.* He received this bonus

although one of the assets he was responsible for managing, the Sterling I pipeline, ruptured, causing an explosion that killed Danielle Smalley and Jason Stone. *Id.*

2. Spills/Leaks From the Crude Oil Pipelines and Resulting Pollution

The United States filed two suits against Koch asserting that over 300 leaks and ruptures of Koch's crude oil pipelines spilled 55,000 barrels or 2.3 million gallons of oil in navigable waters in the States of Texas, Oklahoma, Louisiana, Kansas, Missouri and Alabama during the years of 1990 through 1995. *App. Vol. 3, Tabs 41 and 42.* The United States claimed that the spills occurred because of the poor maintenance and severe corrosion of the pipelines, and Koch's failure to comply with the Clean Water Act. *Id.* The United States also alleged that ruptures and spills from the crude oil pipelines were continuing. The government sought recovery of statutory penalties and injunctive relief. *Id.* The State of Texas filed a complaint in intervention in the Clean Water Act cases. *App. Vol. 3, Tabs 43 and 44.*

Experts for the United States and State of Texas concluded that the ruptures of Koch's crude oil pipelines occurred because: (a) Koch failed to operate the pipeline system in a reasonable and prudent manner; (b) the majority of Koch's pipeline spills were attributed to corrosion; (c) the percentage of pipeline spills due to corrosion indicated a long-term corrosion problem within Koch's pipeline system and leak prevention program; (d) Koch's pipeline assessment program indicated deficiencies in corrosion prevention, personnel training, pipeline depths and over-pressure prevention within its pipeline systems; (e) the average volume quantity per spill release has increased over time indicating leaks are occurring in pipelines with higher flow volumes; (f) Koch failed to adhere to regulations implemented under the Pipeline Safety Act, 49 U.S.C. § 60101 *et seq.*, regarding external corrosion control; (g) Koch failed to monitor the rate of internal corrosion of their pipelines; (h)

Koch's own internal pipeline assessment program estimated costs totaling \$98 million to recondition its pipelines to industry standards reflecting the inadequate condition of its pipeline system; and (i) Koch was deficient in the adequacy of their pre-acquisition investigation of pipeline systems they acquired. *App. Vol. 3, Tab 45.*

Experts for the United States and the State of Texas also concluded that Koch was aware of the extensive leaks that were caused by corrosion at least 7 years before they performed their pipeline assessment program. *Id.* It was the further conclusion of the government's experts that Koch performed an economic evaluation as a result of their pipeline assessment program and decided to sell off many of their poorly conditioned crude oil pipelines rather than shutting them down or expending the costs to recondition the pipelines to industry standards. *Id.*

The Gum Hollow Creek spill near Corpus Christi was one of the 300 spills included in the Clean Water Act suits. *App. Vol. 1, Tab 23.* This pipeline ruptured spewing more than 90,000 gallons of crude oil into Gum Hollow Creek and creating a 12 mile long slick on Nueces and Corpus Christi Bays. Two years before the October 1994 rupture, employees of Koch warned of corrosion and weakness of the pipeline and recommended that sections be replaced. Employees also recommended that a smart pig be run through the line as the number one action step for 1992 and 1993. *App. Vol. 3, Tab 46, V. 3 - Pages 463-464, 483.* The employees were told to hold off on the smart pig test until there was slack time in the pumping schedule. The smart pig test was not performed until 1995. *App. Vol. 3, Tab 47, Page 81.* Koch's own expert, Edmond Murray, Jr., conceded that cathodic protection on the pipeline did not meet Koch's standards. *App. Vol. 3, Tab 46, V. 3 - Pages 481-482, 502.*

Initially, Koch reported the Gum Hollow Creek spill to be approximately 10 barrels or 420 gallons. *App. Vol. 3, Tab 48, Page 13-14*. Nine days later, Koch gave a new estimate of 2,151 barrels or 90,342 gallons. *App. Vol. 3, Tab 49, Pages 163, 176*. Garry Mauro, the Texas Land Commissioner at the time of the spill, testified that Koch's original spill report hindered cleanup efforts. *App. Vol. 3, Tab 48, Pages 14-15*. Mauro testified that spills are routinely calculated within hours, not days, and that his staff suspected that Koch was hoping regulatory agencies would walk away from the spill so it could clean it up with little scrutiny. *Id. at Pages 20, 22-23*.

The United States and State of Texas settled their Clean Water Act claims against Koch for approximately 35 million dollars. *App. Vol. 3, Tab 50*. As part of the settlement, Koch also agreed to a Consent Decree in which the United States District Court for the Southern District of Texas, Houston Division, retains jurisdiction over the operation and maintenance of Koch's crude oil pipelines, although the court's jurisdiction does not relieve Koch of its duty to comply with the Pipeline Safety Act and federal regulations. *Id.* With respect to its crude oil pipelines, Koch is required to take the following action pursuant to the Consent Decree: (a) conduct inspections of its crude oil pipelines; (b) complete the development and implementation of leak detection and leak prevention programs for its crude oil pipelines; and (c) complete the development and implementation of a maintenance and inspection program for its crude oil pipelines. The Consent Decree also provides that Koch's compliance shall be audited by an independent third-party auditing firm, and Koch shall not sell, lease or otherwise transfer any crude oil pipelines without making available all material operations and maintenance records in its possession or control regarding the condition of such pipelines. *Id.*

3. Criminal Indictments and Guilty Pleas

a. Corpus Christi, Texas Refinery

In September 2000, a Texas federal grand jury returned a 97-count indictment against Koch and four employees charging that they violated federal environmental laws at a Corpus Christi refinery and made false statements to the Texas Natural Resource Conservation Commission (TNRCC). *App. Vol. 3, Tab 51*. Again, Koch's conduct leading up to the federal indictment shows its history of failing to correct a known environmental hazard because of the cost of doing so, and the extent to which Koch will go to conceal its lack of compliance with environmental and safety regulations.

According to the indictment, Koch was limited by law to allowing emission wastes of not more than six megagrams of uncontrolled benzene per year at its West Plant or Corpus Christi refinery. (A megagram equals a metric ton or approximately 2,200 pounds.) *Id.* The indictment charged that in January 1995, Koch put into operation a Thermatrix oxidizer, a control device that when working effectively acts like a high-temperature furnace meant to neutralize benzene converting it into carbon dioxide and water. *Id.* The Thermatrix did not have the capacity to handle all the benzene the plant produced. As a result, Koch built bypass stacks to vent benzene vapors directly into the atmosphere without going through a purification system. *Id.*

The federal indictment alleged that to cover up the Thermatrix failures, an in-house Koch attorney (who later became the environmental manager at the refinery and was named individually in the indictment), told employees to call the repeated Thermatrix failures "upsets" to conceal the fact that the Thermatrix lacked sufficient capacity to serve as a control device to destroy benzene emissions. *Id.* In April and August 1995, Koch filed quarterly reports on benzene compliance with

the TNRCC and purposely concealed the refinery's benzene emissions. The quarterly reports also concealed the fact that Koch had not run any tests to determine how much benzene the plant was releasing. *Id.* Although Koch management was aware of the filing of these false reports, they did not revise the reports or cause the reports to be revised. *Id.* In May 1995, raw data indicated the refinery had exceeded its yearly six megagram limit for benzene emissions but Koch made a conscious decision to continue operating the refinery without taking any steps to correct the problem. *Id.* In September 1995, Koch's in-house attorney hired an environmental consulting firm to evaluate whether the plant was in compliance with benzene regulations. In October 1995, the firm advised Koch that it had exceeded its yearly six megagram limit for 1995. *Id.*

The indictment alleged that in January 1996, Koch was aware that the refinery had released 91 megagrams of uncontrolled benzene, 85 megagrams more than the annual six megagram limit. *Id.* The indictment charged that the following month Koch met with the TNRCC on at least two occasions and made false statements about the refinery's benzene emissions. *Id.* The federal indictment further alleged that in April 1996, Koch submitted its annual benzene compliance report for 1995 to the TNRCC which stated that the plant released just 0.61 megagrams total of uncontrolled benzene. The indictment claimed that Koch made these false statements to the TNRCC even though it had known for a considerable time that the refinery's uncontrolled benzene emissions grossly exceeded the yearly six megagram limit. *Id.*

According to the indictment, a technician who had worked for Koch since 1991 was assigned to prepare the annual benzene compliance report for the TNRCC. When the technician discovered that the report that was submitted to the TNRCC did not reflect Koch's lack of compliance with the six megagram limit, she reported same to her bosses. *Id.* On April 16, 1996, the technician advised

the TNRCC of Koch's false benzene compliance report. The technician eventually left her employment with Koch on July 31, 1996, and filed a wrongful termination suit against Koch in 1997 alleging that Koch retaliated against her for complaining about and disclosing the false benzene compliance report. *Id.* The TNRCC's investigation of Koch's benzene emissions and the federal indictment against Koch resulted from the technician's disclosure of Koch's actual benzene emissions, the false report and Koch's deceptions. *Id.*

Significantly, the indictment alleged that money or increased corporate profits was Koch's motivation for failing to correct and for purposely concealing an environmental hazard and lack of compliance with regulations. *Id.* The United States alleged that Koch concealed material facts related to benzene emissions to avoid the loss of profits that would result if the refinery were shut down until it could meet the requirements of the benzene emission standards. Specifically, the original federal indictment stated that "[i]t was further an object of the conspiracy to avoid or delay the financial expenditures necessary to comply with the law and to avoid shutting down the West Plant until it could be brought into compliance with the benzene [emission standards] so as to maximize corporate profits." *Id.* The United States further alleged that Koch made approximately \$251 million in profits in 1995 and 1996 from the operation of its Corpus Christi refineries. *Id.*⁶

On April 9, 2001, Koch Petroleum Group, L.P. ("Koch Petroleum") pled guilty to one count before the Honorable Janis Graham Jack of the United States District Court for the Southern District of Texas, Corpus Christi Division. In pleading guilty, Koch Petroleum admitted that it "did

⁶ On or about January 11, 2001, a Superseding Indictment was filed against Koch and its four employees relating to the operation of the Corpus Christi refinery. The Superseding Indictment narrowed the criminal charges to nine counts but did not alter the core charges or allegations of the United States against Koch and its employees. Prior to the trial date, the United States reduced the charges to seven counts. *App. Vol. 3, Tab 52.*

knowingly and willfully falsify, conceal and cover up by a trick, scheme and device, materials facts in a matter within the jurisdiction of the Texas Natural Resources Conservation Commission and the United States Environmental Protection Agency, to wit, the fact that a control device, the flameless thermal oxidizer known as the Thermatrix, had been disconnected from the Edens separator, a source of benzene vapors, and the fact that defendant [Koch Petroleum] had failed to measure the level of benzene entering the aeration basin at the West Plant." *App. Vol. 3, Tabs 53, 54, 55 and 56*. Koch Petroleum received 5 years probation and agreed to pay a fine of \$10,000,000 and perform community service pursuant to § 8B1.3 of the Federal Sentencing Guidelines and 18 U.S.C. § 3553(a). To fulfill this obligation, Koch Petroleum agreed to pay an additional \$10,000,000 to the clerk of the United States District Court as community service funds to be used for air or water quality remediation projects in and around Corpus Christi, Texas. *App. Vol. 3, Tabs 57, 58 and 59*.

b. Rosemount, Minnesota Refinery

Prior to the guilty plea entered with respect to the Corpus Christi refinery, Koch Petroleum pled guilty to criminal charges related to the operation of its Rosemount, Minnesota refinery. In September 1999, the United States filed criminal charges against Koch Petroleum asserting that from December 1992 through August 1999 Koch Petroleum discharged oil into the backwaters and wetlands of the Mississippi River in such quantities as may be harmful. *App. Vol. 4, Tab 60*. The federal indictment further charged that Koch Petroleum rendered inaccurate a monitoring method required to be maintained under the Clean Water Act. *Id.* The indictment charged that Koch Petroleum "discharged wastewater onto the ground on multiple occasions and it increased the weekend flow of the wastewater discharge to the Mississippi River, when no sampling was required,

thereby negligently rendering inaccurate the monthly averages of ammonia that were required to be reported on monthly discharge monitoring reports." *Id.*

Koch Petroleum pled guilty to the charges. In so pleading, Koch Petroleum admitted that the following facts would have been offered to prove the charged offenses beyond a reasonable doubt. *App. Vol. 4, Tab 61.* On August 20, 1997, aviation fuel was discovered to be seeping from a spring into a wetland and an adjoining navigable water in the vicinity of Spring Lake next to the Mississippi River. The seepage of aviation fuel was determined to be from a leak from Tank 16 at the Rosemount refinery. *Id.* By the time the seepage was discovered, the fuel had contaminated portions of the wetland. *Id.*

To prevent the fuel from reaching the Mississippi River, Koch Petroleum placed booms across the surface of the adjoining navigable water to collect the fuel. It also dug a trench which extended into the wetland to collect and pump the fuel as it seeped into the wetland. *Id.* In digging the trench and setting up a recovery system, Koch Petroleum destroyed a portion of the surrounding ecosystem and wild life habitat. *Id.*

As early as February 1992, Koch Petroleum had reason to believe that Tank 16 had holes in its floor. By September 1992, Koch Petroleum through inventory control records had reason to believe that Tank 16 had lost a significant quantity of aviation fuel. *Id.* Koch Petroleum conducted tests of Tank 16, but failed to notify the Minnesota Pollution Control Agency (MPCA) about the leaks or its size. *Id.* In December 1992, Koch Petroleum emptied Tank 16 and took it off line. Koch Petroleum discovered that there were 34 holes in the bottom of the tank. On December 31, 1992, Koch Petroleum notified MPCA about the leaks but stated that the amount of the leak was unknown. *Id.*

In early 1993, Koch Petroleum had reason to believe that Tank 16 had lost between 200,000 and 600,000 gallons of aviation fuel. Although Koch Petroleum was aware that the fuel would eventually reach the Mississippi River if it was not recovered in time, it did not have a comprehensive plan developed to recover the fuel until June 1997. *Id.* In the interim, Koch Petroleum used various ad-hoc methods and equipment in an effort to recover the fuel. *Id.* Koch Petroleum failed to recover the fuel as rapidly and thoroughly as possible and failed to take other reasonable steps to avoid, minimize or abate the pollution of the waters of the United States. *Id.*

Sometime in 1996 and continuing through March 1997, Koch Petroleum also experienced problems with high levels of ammonia in its wastewater. Because ammonia was one of the pollutants regulated by its National Pollutant Discharge Elimination System (NPDES) permit, the discharge of ammonia above certain limits was prohibited. *Id.* Koch Petroleum stacked the high-ammonia wastewater in its storm water ponds and its fire hydrant lagoons. *Id.*

Once the ponds and lagoons had reached their capacity, Koch Petroleum would discharge the wastewater onto the ground using its fire hydrants. Koch Petroleum discharged wastewater onto the ground on multiple occasions between November 1996 and March 1997, dumping millions of gallons of wastewater onto the ground. *Id.* Koch Petroleum also increased the flow of wastewater discharged into the Mississippi River on the weekends. Since it was not required to test the wastewater on the weekends, Koch Petroleum was able to circumvent the weekly monitoring and reporting requirements. *Id.* By increasing the flow on the weekends and not including it in its calculation of the monthly average, Koch Petroleum rendered inaccurate a monitoring method required under its NPDES permit and the Clean Water Act. *Id.*

Koch Petroleum received three years probation and was ordered to pay a criminal fine of \$6,000,000. *App. Vol. 4, Tab 62*. Koch Petroleum was also ordered to pay \$2,000,000 for remediation of the Spring Lake Park Reserve. *Id.* As conditions of its probation, Koch Petroleum was also required to submit to regular or unannounced examinations of its records and facilities by probation officers or any experts retained by the court, and to comply with the recommendations and requirements of the court with respect to ensuring that any compliance program would adequately prevent or detect any further violations of the law. *Id.*

4. Environmental Violations at Koch's Refineries

In December 2000, the United States filed suit against Koch Petroleum for environmental violations of the Clean Air Act arising out of the operation of its Minnesota and Corpus Christi refineries. *App. Vol. 4, Tab 63*. This suit also alleged that Koch Petroleum was in violation of the Resource Conservation and Recovery Act, the Clean Water Act, the Comprehensive Environmental Response, Compensation and Liability Act, and the Emergency Planning and Community Right to Know Act in the operation of its Minnesota refinery. *Id.* Specific violations detailed in the United States' pleading include violations dating from 1994 through December 31, 1999, and Koch Petroleum's environmental violations were alleged to be continuing at the time suit was filed in December 2000. The United States alleged that on at least one occasion, Koch Petroleum failed to monitor over 500 valves at its Minnesota refinery. *Id.* The United States sought injunctive relief ordering Koch Petroleum to comply with applicable statutes and regulations, and civil penalties for Koch Petroleum's past and ongoing violations. *Id.* The State of Minnesota intervened in this suit. *App. Vol. 4, Tab 64*.

The United States and Koch Petroleum entered into a Consent Decree in which Koch Petroleum agreed to pay a civil penalty in the amount of \$4,500,000, and make numerous improvements to its refineries and refinery operations to reduce nitrogen oxide and sulfur dioxide emissions, minimize or eliminate fugitive benzene waste emissions, improve leak detection and repairs, and enhance sulfur recovery performance. *App. Vol. 4, Tab 65*. The injunctive relief program set forth under the Consent Decree will extend over a period of eight years and is estimated to result in a sixty percent reduction of nitrogen oxide and sulfur dioxide emissions at Koch Petroleum's refineries. *Id.*

5. False Claims and Finding of Liability

Koch recently settled a suit in which a jury found that Koch committed over 24,000 violations of the False Claims Act in the reporting of crude oil and gas measurements. *App. Vol. 4, Tabs 66 and 67*. That suit alleged that Koch, through a management-driven scheme, systematically cheated or stole from the United States, certain Indian tribes and other parties millions of dollars in oil and gas royalties. *App. Vol. 4, Tab 68*. Koch's fraudulent scheme and plan was alleged to have included: (a) falsifying a tank's top gauge by recording on the run ticket an oil height less than is actually observed in the tank before pumping; (b) falsifying a tank's bottom gauge by recording on the run ticket an oil height greater than is actually observed in the tank after pumping; (c) falsifying the temperature of the oil in a tank; (d) falsifying the basic sediment and water content of the oil; (e) falsifying the circumstances of a tank when strapping the tank; and (f) falsifying the API gravity or hydrometer temperature of the crude oil on the run ticket. *Id.* The plaintiffs further alleged that Koch made these false claims in order to increase its monetary gain and estimates that profits realized by it from the false claims exceeded \$230 million.

After a lengthy trial, the jury found that Koch committed over 24,000 false claims. *App. Vol. 4, Tab 66*. The penalty phase was to take place next in which the court was to consider the imposition of a civil penalty of not less than \$5,000 or more than \$10,000 for each violation of the False Claims Act. *App. Vol. 4, Tab 67*. Koch settled the False Claims Act case prior to the penalty phase. *App. Vol. 4, Tabs 69 and 70*.

6. Texas Railroad Commission's 1997 Investigation of Koch's Pipelines

In 1997, the Texas Railroad Commission (TRC) conducted an investigation of some of Koch's pipelines in the State of Texas. The investigation covered 6,836 miles of pipeline, including intrastate, some interstate, and non-regulated lines. *App. Vol. 5, Tab 71*. A portion of Koch's interstate system was inspected under temporary authority from the United States Department of Transportation which expired at the end of calendar year 1997. Only 30 percent of the interstate system was inspected before expiration of the TRC's temporary authority. *Id.*

Of the only 30 percent of the interstate system inspected, the TRC documented at least 150 violations. *App. Vol. 5, Tabs 72 and 73*. The TRC's investigation also revealed that corrosion was the primary cause of leaks on Koch's pipelines. *App. Vol. 5, Tabs 73 and 74*. The TRC also documented numerous violations of inadequate cathodic protection and Koch's failure to take prompt remedial action to correct the cathodic protection deficiencies. *App. Vol. 5, Tab 73*.

Koch paid the TRC a mere \$22,500 in administrative penalties for violations committed with respect to its intrastate pipelines. *App. Vol. 5, Tab 71*. Koch also agreed to pay \$50,000 to Texas Tech University to fund research to enhance pipeline safety. *Id.*

The DOT was suppose to continue the inspection of Koch's interstate pipeline system in 1998. *Id.* Based on available public information, the Office of Pipeline Safety (OPS) conducted

some additional review of Koch's interstate natural gas pipeline system, now operated by Gulf South. The OPS sent warning letters to Koch dated September 30, 1998, October 8, 1998, and April 15, 1999, documenting numerous locations where the cathodic protection was inadequate and stating that Koch had failed to take prompt remedial action to correct the cathodic protection deficiencies. *App. Vol. 5, Tabs 75, 76 and 77.* In most instances, the cathodic protection deficiencies were documented for several years. *Id.* The OPS's letters also listed other violations including lack of external corrosion control, failure to perform inspections of rectifiers, failure to inspect right-of-ways which had become overgrown with brush, and lack of atmospheric corrosion control. *Id.* In the April 15, 1999 warning letter, the OPS noted that the interstate natural gas pipelines in the Goodrich area and Longview area showed signs of atmospheric corrosion and demonstrated a lack of remedial measures for the prevention of atmospheric corrosion. This warning letter further stated that "[i]t appeared that the pipelines have been exposed to the atmosphere for some time." *App. Vol. 5, Tab 77.* These are some of the same natural gas pipelines that Kenoth Whitstine previously advised Koch were exposed above ground and likely to cause injury or harm, including injury to drivers of logging trucks who crossed an exposed pipeline daily. *App. Vol. 1, Tab 13, Pages 43-53, 57-58.*

Although numerous violations were documented with respect to the interstate pipeline system, the only action taken by the OPS was to send warning letters to Koch. These letters state that while Koch was subject to a civil penalty for each violation for each day, no penalty would be assessed. The letters also state that the OPS would only take other action if a continued violation came to its attention. *App. Vol. 5, Tabs 75, 76 and 77.*

I. The OPS Lacks The Resources And Staff To Monitor The Defendants

The OPS is the federal agency responsible for regulating and monitoring the pipeline industry. OPS is part of the Research and Special Projects Administration of the DOT. The OPS has only 55 inspectors nationwide. Since 1990, there have been nearly 4,000 incidents reported to the OPS involving gas and hazardous liquid pipelines, more than one every single day. The OPS has one of the worst records in implementing NTSB safety recommendations, 68.9 percent, and several recommendations made in 1992 have still not been implemented. The OPS has spent many years attempting to construct a national pipeline map but has yet to complete the task. *App. Vol. 1, Tab 23; App. Vol. 2, Tab 26.*

In May 2000, the Government Accounting Office (GAO) issued a report on its audit of the OPS in which it highlighted the fact that the OPS has actually decreased the proportion of enforcement actions with proposed fines from 49 percent to 4 percent. *App. Vol. 5, Tab 78.* Yet, the GAO warned that the OPS has reduced fines without having evaluated whether this approach is effective in achieving compliance with pipeline regulations. *Id.*

Pipeline companies are left largely on their own to determine safety procedures and report pipeline leaks and spills. *Id.; App. Vol. 1, Tab 23.* The OPS simply does not have the resources or staff needed to monitor this industry or the thousands of miles of aging pipeline that cross this country. As a result, pipeline companies are often operating unchecked and without the oversight needed to bring companies such as the Defendants into compliance. *Id.* The Defendants' past and current record of regulatory violations clearly reflects that the OPS is ill-equipped to monitor the operation of their hazardous liquid and natural gas pipelines or enforce compliance with the Pipeline Safety Act and federal regulations. *App. Vol. 1, Tab 23; Vol. 2, Tab 26.*

II.

STATUTORY NOTICE

A. The Timing Of Hamilton's Notice Does Not Require Dismissal

The facts regarding Hamilton's effort to notify Koch and the Secretary of Transportation, as required by 49 U.S.C. § 60121(a)(1)(A), are undisputed. Hamilton sent his notice letter to the Secretary of Transportation on June 5, 2001. *See Hamilton's Notice Letter attached as Exhibit A to his Original Complaint.* A copy of the notice letter was sent to Koch. On June 8, 2001, Hamilton filed his Complaint in this Court. Since that time, over 100 days have passed, during which time neither Koch nor the Secretary of Transportation has acted to address any of the violations alleged in Hamilton's lawsuit.

Instead, relying on a procedural technicality, Koch has asked the Court to dismiss Hamilton's Complaint with prejudice based on the Supreme Court's holding in *Hallstrom v. Tillamook* that the 60-day notice requirement is a "mandatory, not optional" precondition to filing suit. 493 U.S. 20, 26 (1989).

While Hamilton acknowledges, as he must, that the Supreme Court required dismissal in *Hallstrom*, Hamilton submits that the appropriate remedy here, if any, is an order staying or abating this case for 60 days. Such a result would be in keeping with the Pipeline Safety Act, it would promote judicial economy, avoid delay, and further promote Congressional intent in enacting citizen suit provisions in environmental statutes.

First, nothing in the language of the Pipeline Safety Act itself compels dismissal for noncompliance with the Act's notice requirement. *See* 49 U.S.C. § 60121(a)(1)(A). The statute is

completely silent on this issue. Therefore, there is nothing within the four corners of the Act that requires the Court to dismiss Hamilton's Complaint instead of ordering a stay or abatement.

Second, the opinion in *Hallstrom* notwithstanding, the Supreme Court has held in an earlier case that noncompliance with a statutory 60-day delay requirement does not necessarily require dismissal of the action. *See Oscar Mayer & Co. v. Evans*, 441 U.S. 750 (1979). In *Oscar Mayer*, the Court interpreted a 60-day delay requirement under § 14(b) of the Age Discrimination in Employment Act of 1967, which provides in part that "no suit may be brought under section 626 of this title before the expiration of sixty days after proceedings have been commenced under the State law." *Id.* at 753. The Court held in *Oscar Mayer* – as it later did in the *Hallstrom* opinion – that the 60-day notice requirement was a "mandatory, not optional," precondition to suit. *See* 441 U.S. at 764-765. But the Court also held that, rather than dismissing the suit, the court should hold it in abeyance for 60 days, after which the suit could proceed. *Id.* This is the appropriate result here as well.

The Court's reasoning in *Oscar Mayer* is equally applicable: "Suspension of proceedings is preferable to dismissal with leave to refile. . . . To require a second 'filing' by the aggrieved party after termination of the state proceedings would serve no purpose other than the creation of an additional procedural technicality." *Id.* at 766, n. 13. Similarly, dismissal of Hamilton's Complaint followed by immediate refiling serves no legitimate purpose.

Furthermore, dismissing this suit, as Koch demands, and thereby triggering an immediate refiling by the same plaintiff, against the same defendants, regarding the same facts, and alleging the same violations would hinder, rather than promote judicial economy. A dismissal and subsequent

refiling would only create delay and additional expense while putting all parties back in their present position.

A 60-day stay of this proceeding in lieu of dismissal will not prejudice Koch or the Secretary in any respect. Koch and the Secretary will still have the same opportunity to address Koch's multiple violations of the Pipeline Safety Act. The simple fact is that Koch and the Secretary of Transportation now have had notice of Koch's violations for over 100 days with no signal from either entity of administrative or corrective action. Aside from trying to dismiss this suit, Koch has not lifted a finger to address Hamilton's claims. Having passed on a 100-day plus opportunity to take action on Hamilton's claims, the likelihood that Koch will do so after a dismissal and refiling of this suit is nil.

In addition, staying this proceeding for 60 days would serve the same purposes as a dismissal. The Court in *Hallstrom* identified two purposes that Congress intended notice requirements to serve:

First, notice allows government agencies to take responsibility for enforcing environmental regulations, thus obviating the need for citizen suits . . .

Second, notice gives the alleged violator 'an opportunity to bring itself into complete compliance with the Act and thus, likewise render unnecessary a citizen suit.'

493 U.S. at 29. A 60-day stay readily satisfies both of these concerns while dismissing this lawsuit just creates "an additional procedural technicality" that the Court in *Oscar Mayer* expressly disfavored. 441 U.S. at 766, n. 13. Likewise, a 60-day stay would promote Congress's intent in permitting and encouraging citizen actions. *See, e.g.*, S. Rep. No. 91-1196, pp. 36-37 (1970) (legislative history of similar provision of Clean Air Amendments of 1970, 42 U.S.C. § 7604).

Finally, Koch's demand that the court dismiss this proceeding with prejudice is wholly unwarranted. A dismissal with prejudice would not only be a highly inequitable result, but it would also be in direct contradiction to the Supreme Court's order in *Hallstrom* that the district court dismiss without prejudice to refile. 493 U.S. 20 at 32 ("Nor will the dismissal of this action have the inequitable result of depriving petitioners of their 'right to a day in court.' Petitioners remain free to give notice and file their suit in compliance with the statute to enforce pertinent environmental standards."). Dismissing this proceeding with prejudice, particularly on the basis of a procedural technicality, would only serve to frustrate Congress's intent to permit and encourage citizen actions. Therefore, the proper course is for the Court to abate or stay this case for 60 days.

B. Hamilton Was Not Required To Notify State Authorities

Koch next argues that Hamilton's Complaint should be dismissed because he failed to notify the appropriate state authorities that have jurisdiction over Koch's numerous intrastate pipelines. This argument should be rejected because Hamilton complied with the notice provision, 49 U.S.C. §60121(a)(1)(A), by notifying the Secretary of Transportation and Koch about alleged violations of the Act. *See Hamilton's Notice Letter attached as Exhibit A to his Original Complaint.*

Under 49 U.S.C. § 60121(a)(1)(A), a citizen suit plaintiff must give notice "to the Secretary of Transportation *or* to the appropriate State authority (when the violation is alleged to have occurred in a State certified under section 60105 of this title) and to the person alleged to have committed the violation." (Emphasis added.) As this provision provides, a plaintiff may either notify the Secretary or the state authority of alleged violations. Arguably, the only reason that a plaintiff would have to notify state authorities instead of, or in addition to, the Secretary of Transportation is if his lawsuit

involved a state authority's regulation of its intrastate pipeline facilities and intrastate pipeline transportation under section 60105. *See* 49 U.S.C. 60105(a).

It is plain from Hamilton's Complaint, however, that his lawsuit involves only Koch's interstate pipelines, including the Sterling I, Sterling II, and Chaparral pipelines, not Koch's intrastate pipelines. *See Hamilton's Original Complaint at ¶¶ 14-20*. The OPS has jurisdiction over interstate pipelines. Therefore, Hamilton was not required to notify state authorities. For that reason, Koch's argument should be rejected.

C. Hamilton's Notice Sufficiently Identified Koch's Violations

Koch argues that Hamilton's notice letter fails to identify the "particular pipeline system, event, location, date, product" involved in each violation. *See Koch's Motion to Dismiss*, at 5. However, the sufficiency of notice standard applied by the Eastern District of Texas simply does not require the level of specificity demanded by Koch.⁷

In *Friends of the Earth, Inc. v. Chevron Chemical Co.*, 900 F. Supp. 67, 77 (E.D. Tex. 1995), the Eastern District of Texas embraced the 'overall sufficiency' approach established by the Third Circuit in *Public Interest Research Group of New Jersey, Inc. v. Hercules, Inc.*, 50 F.3d 1239, 1248 (3rd Cir. 1995). In *Friends of the Earth*, U.S. District Judge Richard Schell reviewed the sufficiency of notice in a Clean Water Act case and noted that "a strict application of the notice requirement can be procedurally unwieldy for litigants and courts." *Id.* at 77.

⁷ It should be noted that as to the form and substance of the notice, the Pipeline Safety Act states, "The Secretary [of Transportation] shall prescribe the way in which notice is given under this subsection." 49 U.S.C. 60121 (a)(1)(C). However, the Secretary of Transportation has not yet articulated guidelines as to what constitutes sufficient notice under the Pipeline Safety Act. Thus, in the absence of such guidelines, the court may look to notice guidelines in similar environmental statutes.

The “overall sufficiency” approach adopted by the Third Circuit in *Hercules* requires that “the content of the notice must be adequate for the recipients of the notice to identify the basis for the citizen’s complaint.” 50 F.3d at 1249. However, “the citizen is not required to list every specific aspect or detail of every alleged violation. Nor is the citizen required to describe every ramification of a violation.” *Id.* at 1248.

The court in *Hercules* noted that the legislative history behind Congress’s delegating to the EPA⁸ the task of determining the form of the notice shows that Congress sought “to strike a balance between providing notice recipients with sufficient information to identify the basis for the citizen’s claim and not placing an undue burden on the citizen.” *Id.* at 1246. Moreover, it shows that Congress believed that “the regulations should not require notice that places impossible or unnecessary burdens on citizens but rather should be confined to requiring information to give a clear indication of the citizen’s intent.” *Id.* (citing S. Rep. No. 92-414 at 80 (1971), 92d Cong. 1st Sess., reprinted in 2 Legislative History of the Water Pollution Control Act Amendments of 1972 at 1498 (1973)); see also *Atlantic States Legal Found. Inc., v. Stroh Die Casting Co.*, 116 F.3d 814, 819 (7th Cir. 1997) (construing the Clean Water Act and rejecting argument that, under *Hallstrom*, “notice must specifically identify the point source from which the allegedly offending discharge is emerging before the Act’s jurisdictional requirements will be met”).

Hamilton’s notice letter clearly indicates his intent to seek injunctive relief for no less than forty-seven specific violations of the Pipeline Safety Act with respect to Koch’s interstate hazardous

⁸ The EPA articulates what constitutes proper notice for most environmental statutes. For example, the EPA’s regulations for the Clean Air Act, FWPCA, the Safe Drinking Water Act, CERCLA, and EPCRA all require the citizen to serve notice on the appropriate entities by certified mail or personal service. Hamilton served his notice to Koch and the Secretary by certified mail.

liquid pipelines and natural gas pipelines. *See Hamilton's Notice Letter attached as Exhibit A to his Original Complaint.* To provide the specific details as to the date, location, and pipeline system for each violation, however, would place an impossible and unnecessary burden on Hamilton given the relative inaccessibility of the subject matter of this lawsuit – underground natural gas and hazardous liquid pipelines.

Hamilton has set out here and in the attached affidavits specific violations of federal laws by Koch. *See App. Vol. 1, Tab 4, Affidavit of P.D. Hamilton; App. Vol. 1, Tab 14, Affidavit of Bobby Conner; App. Vol. 1, Tab 18, Affidavit of James Freeman; App. Vol. 1, Tab 23, Affidavit of Linda Eads; and App. Vol. 2, Tab 26, Affidavit of Edward R. Ziegler, P.E., C.S.P.* Even so, Koch would certainly not allow Hamilton to dig up the pipeline running across his property to conduct a visual inspection for additional violations. Moreover, Koch has in its possession the documents and records relevant to the maintenance and condition of Koch's pipelines. Absent discovery to determine the condition and maintenance history of these pipelines, the exact time and location of specific violations are available only to Koch. To demand that Hamilton set forth details for each violation would be an impossible and unnecessary burden that is not called for under the 'overall sufficiency' approach.

The evidence that Hamilton has already submitted to this Court shows that Koch's violations occur throughout its entire pipeline system. Violations such as failing to control and monitor corrosion, correct cathodic protection deficiencies, and conduct pipeline inspections, maintenance and repairs have occurred on repeated occasions and are continuing to occur systemwide by many individuals. To require that Hamilton catalog each and every instance in which Koch has failed to maintain cathodic protection, control corrosion, correct cathodic protection deficiencies, or conduct

proper inspections, maintenance and repairs on a certain date at a certain location and by a certain individual would be an unreasonable and impossible burden given the massive and continuing scale by which these violations occur.

Hamilton seeks injunctive relief against Koch precisely because the dangerous condition of Koch's natural gas and hazardous liquid pipeline exists on a massive and continuing scale across its entire pipeline system. Piecemeal relief will not remedy a dangerous condition that may affect the safety of thousands of families across Texas, Oklahoma, Kansas, Louisiana, Alabama, Mississippi and Florida. As detailed in the factual section of this response, Koch's violations are not limited to only pipeline leaks, but include management decisions, management philosophy and operating procedures which have the cumulative effect of creating the current "swiss cheese" condition of Koch's pipeline system.

Koch's argument that Hamilton's notice provides no information by which "either the government or Koch could even begin to research, investigate, or identify" the violations is simply untrue. Certainly, Koch can determine whether it has any pipelines that are exposed or not buried deep enough; Koch can determine whether its pipeline markers accurately mark the locations of its pipelines; Koch can identify any pipeline leaks or spills; Koch can determine whether proper inspections, maintenance and repairs have been performed; Koch can identify the level of corrosion of its pipelines; Koch can determine whether each pipeline has adequate cathodic protection; Koch can determine whether it has maintained appropriate maps and records of each repair made to the pipelines for the life of the pipelines; and Koch can identify pipelines which operate at a pressure that exceeds the pipeline design or eighty percent of any hydrostatic test. The simple fact is that

discovery is likely to reveal that Koch has already done this research but has chosen to ignore the results.

Koch relies on *Southwest Center for Biological Diversity v. U.S. Bureau of Reclamation*, 143 F.3d 515 (9th Cir. 1998) as an absolute bar against bringing suit. But *Southwest Center* is easily distinguishable. In that case, none of the notice letters even mentioned that Southwest had a grievance about the Flycatcher habitat, which was a substantial basis for Southwest's lawsuit. *Id.* at 522. In contrast, Hamilton's notice letter clearly informs Koch and the Secretary that "Koch's natural gas and hazardous liquid pipeline have seriously deteriorated in condition and expose P.D. Hamilton and the class members to imminent harm. . . .[and] have caused and is continuing to cause damage to the property of the Trust, P.D. Hamilton and the class members." *Hamilton's Notice Letter at 2 attached as Exhibit A to his Original Complaint.*

Koch also relies on *Hudson Riverkeeper Fund, Inc. v. Putnam Hospital Center, Inc.*, 891 F. Supp. 152 (S.D.N.Y. 1995). This case is also distinguishable. In *Hudson Riverkeeper*, a specific EPA regulation required that notice of intent-to-sue under the Clean Water Act contain:

sufficient information to permit the recipient to identify the specific standard, limitation, or order which has allegedly been violated, the activity alleged to be in violation, the person or persons responsible for the alleged violation, the location of the alleged violation, **the date or dates of such violation**, and the full name, address, and telephone number of the person giving notice.

40 C.F.R. 135.3(a)(1994) (emphasis added). The notice letter was deemed insufficient because it failed to specify a time-frame when the violations occurred as mandated by the EPA guidelines.

The notice guidelines under the Clean Water Act do not control in this case. The Secretary of Transportation has not articulated specific guidelines for notice under the Pipeline Safety Act. Given the lack of specific guidelines under the Pipeline Safety Act, the massive and continuing

scale of Koch's violations, as described above, and the unreasonable and unnecessary burden in cataloging each specific violation, Hamilton's notice letter is sufficient under the approach established by the Third Circuit in *Hercules* and embraced by the Eastern District of Texas in *Friends of the Earth*. Thus, Koch's motion to dismiss on this ground should be denied.

III.

HAMILTON HAS PRESENTED AMPLE EVIDENCE OF HIS STANDING

Koch argues that Hamilton lacks standing under Article III, Section 2 of the United States Constitution to bring this suit. To satisfy Article III's standing requirements, Hamilton must show (1) he has suffered an "injury in fact" that is concrete and particularized and actual or imminent, not conjectural or hypothetical; (2) the injury is fairly traceable to the challenged action of the defendant; and (3) the injury is likely, as opposed to merely speculative, to be redressed by a favorable decision. *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs., Inc.*, 528 U.S. 167, 180-81 (2000).

At the pleading stage, general factual allegations of injury resulting from the defendant's conduct suffice to establish standing, for on a motion to dismiss, the court presumes that general factual allegations embrace those specific facts that are necessary to support the claim. *Bennett v. Spear*, 520 U.S. 154, 168 (1997); *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 561 (1992). Although not required to do so at the pleading stage of this case, Hamilton has presented evidence of his actual injury caused by Koch's unlawful conduct that is likely to be redressed by the injunctive relief sought. *App. Vol. 1, Tab 4, Affidavit of P.D. Hamilton*.

Hamilton has approximately 420 acres of rural property that he uses for a commercial cattle operation, including mixed and Semmental-Angus cross bred cattle. *Id.* Hamilton and his family,

including his children and grandchildren, also use the property for recreation and hunting. *Id.* Additionally, there is a deer lease on the property and Hamilton leases the property to others for hunting. *Id.* A camp house located on the property is used to sleep overnight. *Id.*

Koch's Sterling II pipeline, transporting liquid petroleum gas, and a Koch natural gas pipeline cross the property. *Id.*; *App. Vol. 1, Tab 5*; *App. Vol. 2, Tab 26, Affidavit of Edward R. Ziegler, P.E., C.S.P.* The only information Hamilton has received from Koch about a pipeline or pipeline emergency is a calendar received approximately three years ago. *App. Vol. 1, Tab. 4, Affidavit of P.D. Hamilton.*

Before filing suit, Hamilton became concerned that the pipelines might be exposed or not buried deep enough to be safe because the ground over or around the pipelines has eroded or settled. *Id.* Hamilton was also concerned about whether the pipelines are properly marked, have any leaks, have sufficient integrity to be safe, are being operated safely, and have been properly inspected. *Id.* Additionally, Hamilton was concerned because he has not received sufficient information from Koch about pipelines and pipeline emergencies. *Id.* Before filing suit, Hamilton also learned that Koch has had other problems with the safety of its pipelines, including the Kaufman County explosion and hundreds of leaks from its crude oil pipelines. *Id.*

An inspection of the Koch pipelines on Hamilton's property has confirmed that Sterling II is buried less than 30 inches deep in some locations, constituting a safety-related condition that has not been remedied by Koch. 49 C.F.R. §§195.248, 195.401(b). *App. Vol. 2, Tab 26, Affidavit of Edward R. Ziegler, P.E., C.S.P.* Likewise, the natural gas pipeline, which is located very near and parallel to the Sterling II line, is buried as shallow as 8 inches deep in some locations. As a result, the operation of the natural gas pipeline at such a shallow depth poses a serious danger and

immediate hazard to Hamilton and his family. 49 C.F.R. §§192.327, 195.401(b). *App. Vol. 2, Tab 26, Affidavit of Edward R. Ziegler, P.E., C.S.P.*

The inspection also confirmed that the Sterling II pipeline is not properly marked to allow Hamilton and others on the property to know the exact location of the pipeline. 49 C.F.R. §195.410 and 49 C.F.R. §195.401(b). *App. Vol. 2, Tab 26, Affidavit of Edward R. Ziegler, P.E., C.S.P.* Koch has also violated and is continuing to violate 49 C.F.R. §195.440 in failing to provide Hamilton with appropriate public education material. *Id.*

Because Hamilton does not believe the pipelines are safe, he has limited the use of that part of the property where the pipelines are located. *App. Vol. 1, Tab 4, Affidavit of P.D. Hamilton.* Hamilton and his family do not use that part of the property for recreation, and he has limited the work performed on that area of the property. *Id.* Recently, Hamilton subsoiled the property, except that portion of the property where the pipelines cross. *Id.* Because the pipelines have not been buried at a sufficient depth or properly marked, activities common to rural property and cattle operations, such as subsoiling, plowing or digging a post hole, place Hamilton and his family in imminent risk of harm. Hamilton has also limited the use of the property because he does not believe he has received sufficient information from Koch about the pipelines and what to do if a pipeline emergency arises. *Id.* Although Hamilton has leased the property to others in the past for deer hunting, he may no longer be able to allow others to hunt or use firearms near the pipelines. *Id.* Finally, Hamilton has stated that he is very concerned the Koch pipelines may leak or rupture, resulting in a fire or explosion that may injure him, his family or any other individuals who may be on the property, and that he believes the Koch pipelines expose him and his family to imminent risk of harm. *Id.*

Hamilton has also attached to this Response, substantial evidence supporting his allegation that Koch's Market-Based Management® policy is contrary to and in violation of the Pipeline Safety Act and related regulations. Koch's Market-Based Management® has resulted in numerous regulatory violations, safety problems, injuries, deaths and environmental offenses. Significantly, wide-spread corrosion and lack of proper maintenance have resulted in the rupture and explosion of the Sterling I pipeline in Kaufman County, over 300 leaks or spills from Koch's crude oil pipelines in 5 states, 150 regulatory violations documented by the TRC during its 1997 investigation, and additional violations documented by the OPS in 1998. Consistent throughout Koch's history of violations is the corporate policy and practice of sacrificing safety for higher profits. Former employees have repeatedly testified that decisions regarding pipeline operations and maintenance are based on whether a profit will be gained.

Pipeline maintenance and repairs, even if recommended by Koch's employees, are denied or delayed to reduce operating costs and increase profits. Koch's Market-Based Management® includes the corporate philosophy that it is cheaper to pay for a leak, rupture or incident than to maintain and repair the pipelines. Koch's Market-Based Management® practice is long-standing and is applied system wide. As a result, the hazardous liquid and natural gas pipelines have been allowed to deteriorate and are being operated in a dangerous condition. These pipelines, including the Sterling II pipeline, expose Hamilton and the class members to imminent risk of harm.

Unlike the plaintiff in *Los Angeles v. Lyons*, 461 U.S. 95 (1983), relied on by Koch, Hamilton's fears and allegations of imminent risk of harm are not speculative. In *Lyons*, the plaintiff lacked standing to seek an injunction against the enforcement of a police chokehold policy because he could not credibly allege that he faced a realistic threat from the policy. *Id.* at 106, n.

7. The reasonableness of the plaintiff's fear was dependent upon the likelihood of a recurrence of the unlawful conduct. *Id.* at 107, n. 8.

By contrast, in *Friends of the Earth, Inc. v. Laidlaw Env'tl. Servs., Inc.*, 528 U.S. 167, 180-81 (2000), the plaintiffs' concerns about the defendant's pollution discharges into the North Tyger River and surrounding area directly affected their recreational, aesthetic and economic interests. The defendant's unlawful conduct was ongoing, thus, the United States Supreme Court stated that the only subjective issue presented was the reasonableness of the fear that led the plaintiffs to refrain from using the river and surrounding area. *Id.* at 184. The Court concluded that "we see nothing 'improbable' about the proposition that a company's continuous and pervasive illegal discharges of pollutants into a river would cause nearby residents to curtail their recreational use of that waterway and would subject them to other economic and aesthetic harms. The proposition is entirely reasonable, the District Court found it was true in this case, and that is enough for injury in fact." *Id.* at 184-85.

Hamilton's concerns about the Koch pipelines that have led to a limitation in the use of his property are completely reasonable given the specific violations that have been identified and Koch's history of favoring profits over pipeline maintenance and safety. Hamilton has sustained an actual and concrete injury in his loss of use of the property, including the loss of the financial or economic benefit derived from the hunting lease. Hamilton's fear that he and his family are exposed to imminent risk of harm from the pipelines is entirely reasonable given Koch's ongoing violations and the resulting danger. Hamilton's injuries are fairly traceable to Koch's failure to comply with the minimum safety regulations and Koch's operation of its pipelines in a dangerous

condition. Further, Hamilton's injuries will likely be redressed if Koch is ordered to correct its violations and enjoined from committing future violations.

Hamilton has more than satisfied the minimal showing of Article III's standing requirements at the pleading stage of this case. *Bennett v. Spear*, 520 U.S. at 168; *Lujan v. Defenders of Wildlife*, 504 U.S. at 561. Accordingly, Koch's Motion to Dismiss should be denied.

IV. INJUNCTIVE RELIEF IS APPROPRIATE

Koch argues that this case should be dismissed because Hamilton's requested injunctive relief is inappropriate, in that it impermissibly seeks an order for Koch to "obey the law." In support of its argument, Koch cites cases in which the injunctive order itself was held to be an impermissible "obey the law" injunction. *See, e.g., Hughey v. JMS Dev. Corp.*, 78 F.3d 1523, 1531 (11th Cir.), *cert. denied*, 519 U.S. 993 (1996); *Louis W. Epstein Family Partnership v. KMart Corp.*, 13 F.3d 762, 771 (3d Cir. 1994); *Payne v. Travenol Lab., Inc.*, 565 F.2d 895, 897-98 (5th Cir.), *cert. denied*, 439 U.S. 835 (1978). These cases, however, do not support a dismissal of Hamilton's request for injunctive relief at the pleadings stage of these proceedings.

The Pipeline Safety Act specifically entitles Hamilton to injunctive relief to halt and correct Koch's regulatory violations. 49 U.S.C. §60121(a)(1). Even at the early stage of this case, Hamilton has presented ample evidence of Koch's regulatory violations warranting the issuance of an injunction.

Hamilton has previously detailed for Koch the specific nature of the injunctive relief he is seeking to correct current regulatory violations and to ensure future compliance. Shortly after filing suit, Hamilton provided Koch with a lengthy document entitled *Emergency Program: Hazardous*

Liquid and Natural Gas Pipeline Integrity and Reliability Improvement, prepared by Hamilton's expert, Edward R. Ziegler, P.E., C.S.P. This comprehensive plan details the action Koch must immediately take to remedy the dangerous threats and hazards Hamilton and the class members face because of Koch's continuous and ongoing violations. *App. Vol. 2, Tab 26 and Emergency Program: Hazardous Liquid and Natural Gas Pipeline Integrity and Reliability Improvement, attached thereto as Exhibit B.* The Emergency Program sets out the action Koch must take to comply with the federal regulations and the industry standards incorporated by the regulations. *Id.* Again, Hamilton has far exceeded his burden at this pleading stage by providing Koch with a detailed plan of the injunctive relief he will seek.

Koch's challenge to Hamilton's request for injunctive relief is premature. All specific injunctive relief to which Hamilton may be entitled must necessarily await further development of the underlying facts. *See, e.g., Commodity Futures Trading Comm'n v. Incomco, Inc.*, 649 F.2d 128, 132 (2d Cir. 1981) (holding that complaint for preliminary and permanent injunctive relief against corporations was prematurely dismissed when the underlying facts were not fully developed and the issue of whether there was a reasonable likelihood of future violations was not yet resolved); *McClenathan v. Rhone-Poulenc, Inc.*, 926 F.Supp. 1272, 1281 (S.D.W.Va. 1996) (reasoning that dismissal of plaintiff's request for injunctive relief in form of independent safety audits of defendant's facility was premature because if plaintiffs could prove their allegations that defendant consciously ignored safety measures in favor of maximizing profits, requested relief could be appropriate). Hamilton must be afforded the opportunity to conduct discovery and present additional evidence of Koch's regulatory violations and the reasonable likelihood that the violations will continue unless enjoined.

Koch's argument also fails because Hamilton's Complaint requests much more than mere obedience of the law. In addition to setting forth — with particularity — the federal regulations that Koch has violated (and continues to violate) and Koch's policy and pattern of ignoring pipeline safety and integrity in favor of maximizing profits, the Complaint seeks to require Koch to conduct the necessary "inspections, testing, close interval surveys and surveillance, repairs, replacements, maintenance and/or retro-fitting of their pipeline" as to eliminate Hamilton's and the class members' exposure to an imminent risk of harm and to prevent further damage to Hamilton's and class members' property. That the Complaint adopts some of the regulatory language from the Pipeline Safety Act does not, in and of itself, render the request for the injunctive relief inappropriate. The Complaint clearly alleges that unless enjoined by this Court, Koch will continue to violate the minimum safety standards prescribed by federal law.

Koch has failed to meet its stringent and exacting burden under Federal Rule of Civil Procedure 12(b)(6) of showing that Hamilton cannot prove any set of facts that would entitle him or the class members to injunctive relief based on the allegations in the Complaint. *See Garrett v. Commonwealth Mortg. Co.*, 938 F.2d 591, 594 (5th Cir. 1991). Accordingly, Koch's Motion to Dismiss should be denied.

V.
COURT SUPERVISION IS NEEDED

Finally, Koch argues that the Court should dismiss Hamilton's Complaint because the injunctive relief he is seeking would require the Court to continuously supervise Koch's compliance with the Pipeline Safety Act and the related regulations enacted by the DOT at 49 C.F.R. Parts 190 through 199.

This argument should be rejected for several reasons. First, the injunctive relief sought by Hamilton is specifically allowed by the Pipeline Safety Act. Section 60121(a)(1) provides that “a person may bring a civil action in an appropriate district court of the United States for an injunction against another person . . . for a violation of this chapter or a regulation prescribed or order issued under this chapter.” 49 U.S.C. § 60121(a)(1). In fact, an injunction is the sole remedy that Congress allowed private citizens for violation of the Pipeline Safety Act. It is absurd to suggest, as Koch does, that the Court should dismiss Hamilton’s claims because the injunctive relief he is seeking would require the Court to interpret and apply provisions of the law regulating Koch. This is exactly the remedy that Congress gave Hamilton and others in enacting the citizen suit provision of the Act.

Second, it would be premature for the Court to dismiss Hamilton’s complaint for injunctive relief before any discovery has taken place, before hearing any evidence and without considering the merits of Hamilton’s position. In this regard, Koch’s argument about the broad scope of the injunctive relief sought by Hamilton is nothing more than an attempt to scare the Court away from the case. The better course is to recognize that Congress enacted section 60121 to allow private citizens such as Hamilton to seek enforcement of the Act through injunctive relief in the district courts of the United States.

None of the cases cited by Koch involved statutes that specifically authorized private citizens to seek injunctive relief. *See The Original Great American Chocolate Chip Cookie Co., Inc. v. River Valley Cookies, Ltd.*, 970 F.2d 273, 275 (7th Cir. 1992) (seeking specific performance of franchise agreement); *8600 Associates, Ltd. v. Wearguard Corp.*, 737 F.Supp 44, 45 (E.D. Mich. 1990) (seeking specific performance of continuous operation clause in commercial lease); *National*

Resources Defense Counsel v. E.P.A., 966 F.2d 1292, 1300 (9th Cir. 1992) (seeking to enjoin EPA from extending permit deadlines); *Walsh v. Ford Motor Co.*, 130 F.R.D. 260, 266 (D. D.C. 1990) (seeking certification of Rule 23(b)(2) mandatory injunctive class in nationwide warranty action). As such, these cases are hardly precedent for the Court to deny Hamilton his right to seek injunctive relief under the Pipeline Safety Act.

Many courts have granted the types of injunctive relief sought here. *See, e.g., Natural Resources Defense Council, Inc., et al. v. Texaco Refining and Marketing, Inc.*, 20 F. Supp. 2d 700 (D. Del. 1998) (enforcing injunction entered against Texaco for multiple violations of the Clean Water Act); *Piney Run Preservation Assoc. v. County Comm'rs*, 82 F.Supp. 2d 464, 473 (D. Md. 2000) (issuing an injunction and maintaining jurisdiction over the case to ensure compliance with the Clean Water Act); *Public Interest Research Group, Inc. v. Star Enter.*, 771 F.Supp. 655, 669 (D. N.J. 1991) (finding that permanent injunction was proper to prevent future permit violations); *Natural Resources Defense Council, Inc. v. Outboard Motor Corp.*, 692 F.Supp. 801, 821-24 (N.D. Ill. 1988) (same).

Fourth, in response to Koch's suggestion that the Court is incapable of managing the relief sought by Hamilton, the Court has many tools at its disposal to insure that Koch complies with any injunctive order the Court issues. Courts have the "inherent power to provide themselves with appropriate instruments for the performance of their duties," including the authority to appoint persons unconnected with the court, such as special masters, auditors, examiners and commissioners, with or without the consent of the parties, to simplify issues and to make tentative findings. *See Ex parte Peterson*, 253 U.S. 300, 314, 40 S.Ct. 543, 547 (1920); *Reilly v. United States*, 863 F.2d 149, 154 n.4 (1st Cir. 1988). For example, courts have routinely appointed special

masters under Federal Rule of Civil Procedure 53 for various tasks: discovery masters, case managers, settlement masters, fact finders, expert advisors, remedial masters, monitors and claims evaluators. *See Active Prods. Corp. v. A.H. Choitz & Co., Inc.*, 163 F.R.D. 274, 282-283 (N.D. In. 1995).

Moreover, as noted by the Manual for Complex Litigation, the Federal Rules of Civil Procedure, particularly Rules 16, 26, 37, 42 and 83, contain numerous grants of authority that supplement the court's inherent power to manage litigation. *See* § 20.1 *Manual for Complex Litigation, Third* (2000). For example, Federal Rule of Civil Procedure 16(c)(12) specifically addresses complex litigation, authorizing the judge to adopt "special procedures for managing potentially difficult or protracted actions that may involve complex issues, multiple parties, difficult legal questions, or unusual proof problems." That is not to mention the court's authority to appoint experts under Federal Rule of Evidence 706. Given the availability of these specific tools, as well as the Court's inherent authority, this Court is certainly capable of implementing and supervising the injunctive relief sought by Plaintiff in his complaint.

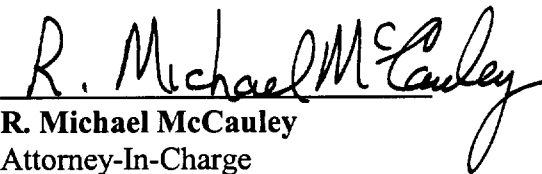
Finally, there is an unintended irony to Koch's argument that actually supports Plaintiff's request for injunctive relief. Namely, by arguing that the Court will have to continuously supervise Koch's conduct, Koch is admitting that it cannot be trusted to follow the law, nor that it can be trusted to obey injunctive orders issued by this Court under 49 U.S.C. § 60121(a)(1). That it will be difficult for the Court to insure Koch's compliance with the law is no reason for the Court to deny Hamilton's request for injunctive relief. Koch has shown time and again that court supervision is the only means to force Koch to abide by the many regulations that protect public safety.

WHEREFORE, PREMISES CONSIDERED, Plaintiff P.D. Hamilton, individually and as Trustee of the Prentice Dell Hamilton and Florine Hamilton Family Trust, and all those similarly situated, respectfully prays that the Court deny the Koch Defendants' Motion to Dismiss, and grant Plaintiff such other and further relief as the Court may deem just and appropriate.

Respectfully submitted,

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The undersigned certifies that a copy of Plaintiff P.D. Hamilton's Response to the Koch Defendants' Motion to Dismiss was served on the Koch Defendants' Attorney-In-Charge via hand delivery, to the Koch Defendants' other attorneys via certified mail, return receipt requested, and to the other parties' attorneys of record via United States mail on the 28th day of September, 2001:

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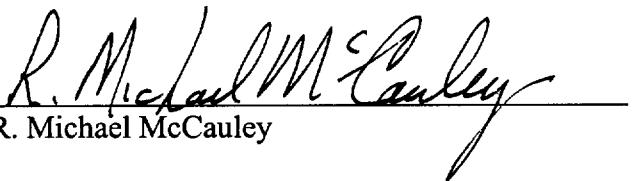
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APPENDIX

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8. Texas Railroad Commission Permit to Operate Pipeline No. 00561, the Chaparral pipeline
9. Texas Railroad Commission Permit to Operate Pipeline No. 01700
10. Texas Railroad Commission Permit to Operate Pipeline No. 00761, the Gulf South natural gas pipeline system
11. Affidavit of Amy Harris and Koch News titled *Entergy-Koch Approved, Open for Business Today*, published at www.kochind.com
12. Affidavit of R. Michael McCauley and Plaintiff's Trial Exhibit No. 118 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
13. Testimony of Kenoth E. Whitstine from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
14. Affidavit of Bobby Conner
15. Gulf South Pipeline Company, L.P. Operations Organizational Chart and Gulf South Operations Job Descriptions, published at www.gulfsouthpl.com
16. Entergy-Koch Corporate Executives, published at www.energykoch.com
17. Entergy-Koch Presentation by Kyle Vann, President and CEO, at the American Gas Association, Financial Forum, May 7, 2001, published at www.energy.com
18. Affidavit of John Freeman and 5 photographs attached thereto
19. Koch Philosophy, published at www.kochind.com
20. INTRODUCTION TO MARKET-BASED MANAGEMENT, with Foreward by Charles G. Koch, Chairman and CEO of Koch Industries, Inc., Exhibit No. 30 to the Deposition of Danny Mills in *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
21. Koch Philosophy titled *How to Succeed in Interesting Times*, by Charles G. Koch, Chairman and CEO of Koch Industries, Inc., published at www.kochind.com
22. Testimony of Phillip Dubose from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas

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- 23. Affidavit of Linda Eads
- 24. Plaintiff's Trial Exhibit No. 119 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 25. Plaintiff's Trial Exhibit No. 50 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas

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- 26. Affidavit of Edward R. Ziegler, P.E., C.S.P. and Exhibits A-I thereto, including the Emergency Program: Hazardous Liquid and Natural Gas Pipeline Integrity Reliability Improvement for Koch Pipeline Company attached as Exhibit B
- 27. Plaintiff's Trial Exhibit No. 31 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 28. Trial Testimony of James Craddock from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 29. Trial Testimony of Edward R. Ziegler, P.E., C.S.P. from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 30. Plaintiff's Trial Exhibit No. 43 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 31. Trial Testimony of Charles Powell, P.E., from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 32. Trial Testimony of James Tucker from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 33. Trial Testimony of Don Carson from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
- 34. Trial Testimony of David Kilian from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas

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35. Plaintiff's Trial Exhibit No. 27 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
36. Plaintiff's Trial Exhibit No. 38 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
37. Trial Testimony of Charles Misak from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
38. Trial Testimony of Roger Floyd from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
39. Deposition and Trial Testimony of Bill Caffey from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
40. Defendants' Trial Exhibit No. 10 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas

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41. Affidavit of Linda Eads and the United States' Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division, and the United States' Revised Motion to Amend Schedule "A" to the Original Complaint
42. United States' Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. 97-CV687B, United States District Court in the Northern District of Oklahoma
43. Intervenor State of Texas' First Original Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division
44. Intervenor State of Texas' First Amended Original Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. 97-CV687B, United States District Court in the Northern District of Oklahoma
45. Expert Report of Rimkus Consulting Group, Inc. on behalf of the United States and State of Texas in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division

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46. Testimony of Edmond Murray, Jr. in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division
47. Testimony of John Lacy in *Harms, et al. v. Koch Gathering Systems, Inc., et al.*, Cause No. 94-6629-H, 347th Judicial District Court of Nueces County, Texas
48. Testimony of Garry Mauro in *Harms, et al. v. Koch Gathering Systems, Inc., et al.*, Cause No. 94-6629-H, 347th Judicial District Court of Nueces County, Texas
49. Testimony of Richard Tuttle in *Harms, et al. v. Koch Gathering Systems, Inc., et al.*, Cause No. 94-6629-H, 347th Judicial District Court of Nueces County, Texas
50. Consent Decree filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division
51. Certified Copy of Indictment filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division
52. Certified Copies of Superseding Indictment, Motion to Dismiss Counts 8 and 9, and Order filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division
53. Certified Copy of Memorandum of Plea Agreement filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division
54. Certified Copy of Criminal Court Minutes filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division
55. Certified Copy of Information filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division
56. Certified Copy of Waiver of Indictment filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division

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- 57. Certified Copy of Re-Arrestment filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division
- 58. Certified Copies of Sentencing and Consent by Board of Directors in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division
- 59. Certified Copy of the United States' Memorandum of Law in Support of Organizational Community Service filed in *United States v. Koch Industries, Inc., et al.*, Criminal No. C-00-325, United States District Court for the Southern District of Texas, Corpus Christi Division

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- 60. Certified Copy of Indictment filed in *United States v. Koch Petroleum Group, L.P.*, Criminal No. 99-270-ADM, United States District Court for the District of Minnesota
- 61. Certified Copy of Plea Agreement and Sentencing filed in *United States v. Koch Petroleum Group, L.P.*, Criminal No. 99-270-ADM, United States District Court for the District of Minnesota
- 62. Certified Copy of Judgment in a Criminal Case filed in *United States v. Koch Petroleum Group, L.P.*, Criminal No. 99-270-ADM, United States District Court for the District of Minnesota
- 63. Certified Copy of the United States' Complaint filed in *United States v. Koch Petroleum Group, L.P.*, Civil Action No. 00-CV-2756, United States District Court for the District of Minnesota
- 64. Certified Copy of the State of Minnesota's Complaint filed in *United States v. Koch Petroleum Group, L.P.*, Civil Action No. 00-CV-2756, United States District Court for the District of Minnesota
- 65. Certified Copy of Consent Decree filed in *United States v. Koch Petroleum Group, L.P.*, Civil Action No. 00-CV-2756, United States District Court for the District of Minnesota

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66. Certified Copies of Jury Verdict Form No. 1 and Jury Verdict Form No. 2 filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
67. Certified Copy of Order Denying Defendants' Motion for Judgment as a Matter of Law filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
68. Certified Copy of Second Amended Complaint for Violations of the False Claims Act filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
69. Certified Copy of Joint Application to Strike the Penalty Phase Proceeding filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
70. Certified Copy of Order filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma

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Tendered For Filing
On _____

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

**APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS**

VOLUME 1 OF 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

**P.D. HAMILTON, Individually and as
Trustee of the Prentice Dell Hamilton and
Florine Hamilton Family Trust**

VS.

**KOCH INDUSTRIES, INC., Individually
and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
GS PIPELINE COMPANY, L.L.C.,
ENTERGY-KOCH, L.P., and
EKLP, L.L.C.**

§ § 87(2)(b), 87(2)(g)

CIVIL ACTION NO. 9:01CV132

**APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS**

VOLUME 1 OF 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

**P.D. HAMILTON, Individually and as
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VS.

CIVIL ACTION NO. 9:01CV132

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and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
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2. Minimum federal safety standards for the transportation of natural gas by pipeline, 49 C.F.R. Part 192 (2000)
3. Minimum federal safety standards for the transportation of hazardous liquid gas by pipeline, 49 C.F.R. Part 195 (2000)
4. Affidavit of P.D. Hamilton
5. Affidavit of Tannis Stone and Texas Railroad Commission Permit to Operate Pipeline No. 04518, the Sterling II pipeline
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10. Texas Railroad Commission Permit to Operate Pipeline No. 00761, the Gulf South natural gas pipeline system
11. Affidavit of Amy Harris and Koch News titled *Entergy-Koch Approved, Open for Business Today*, published at www.kochind.com
12. Affidavit of R. Michael McCauley and Plaintiff's Trial Exhibit No. 118 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
13. Testimony of Kenoth E. Whitstine from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
14. Affidavit of Bobby Conner
15. Gulf South Pipeline Company, L.P. Operations Organizational Chart and Gulf South Operations Job Descriptions, published at www.gulfsouthpl.com
16. Entergy-Koch Corporate Executives, published at www.entergykoch.com
17. Entergy-Koch Presentation by Kyle Vann, President and CEO, at the American Gas Association, Financial Forum, May 7, 2001, published at www.entergy.com
18. Affidavit of John Freeman and 5 photographs attached thereto
19. Koch Philosophy, published at www.kochind.com
20. INTRODUCTION TO MARKET-BASED MANAGEMENT, with Foreward by Charles G. Koch, Chairman and CEO of Koch Industries, Inc., Exhibit No. 30 to the Deposition of Danny Mills in *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
21. Koch Philosophy titled *How to Succeed in Interesting Times*, by Charles G. Koch, Chairman and CEO of Koch Industries, Inc., published at www.kochind.com
22. Testimony of Phillip Dubose from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas

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23. Affidavit of Linda Eads
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26. Internal Revenue Code.
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28. Judiciary and Judicial Procedure.
29. Labor.
30. Mineral Lands and Mining.
31. Money and Finance.
32. National Guard.
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UNITED STATES CODE ANNOTATED

TITLE 49 Transportation §§ 40101 to End

Comprising All Laws of a General
and Permanent Nature
Under Arrangement of the Official Code of
the Laws of the United States
with
Annotations from Federal and State Courts

WEST PUBLISHING CO.
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EXPLANATION

These volumes, comprising Title 49 of the United States Code, contain laws of a general and permanent nature relating to Transportation, including all amendments through Public Law 104-207 which was signed on September 30, 1996.

The nation's economy and society in general are heavily dependent upon transportation. The need for federal government regulation of such a vital and far-reaching industry was recognized by the framers of the United States Constitution in granting Congress the power to regulate commerce. Since that time, legislators have attempted to provide the citizens of this country with safe, economical, and nondiscriminatory means of transportation. One of the earliest and most famous of the transportation laws was "An act to regulate commerce", Feb. 4, 1887, ch. 104, 24 Stat. 379, which was later renamed the Interstate Commerce Act. This landmark in legislation focused on controlling an increasingly monopolistic rail industry and, most importantly, established the Interstate Commerce Commission.

Although the advent of motor vehicle and air transportation drastically increased the need for government regulation over the years, burgeoning competition precipitated a period of deregulation beginning in the early 1980's. For example, the Staggers Rail Act of 1980 deregulated most railroad rates, legalized railroad shipping contracts, simplified abandonments, and stimulated an explosion of service and marketing alternatives. Fierce competition in the trucking industry led to the Motor Carrier Act of 1980, the Household Goods Act of 1980, the Surface Freight Forwarder Deregulation Act of 1986, the Negotiated Rates Act of 1993, and the Trucking Industry Regulatory Reform Act of 1994. Similar trends in the airline industry resulted in the Federal Aviation Administration Act of 1994. Years of deregulation and erosion of the powers of the Interstate Commerce Commission culminated recently with the ICC Termination Act of 1995. This important piece of legislation substantially deregulated both the rail and motor carrier industries, abolished the 108-year old Interstate Commerce Commission, and established in its place the Surface Transportation Board.

Additional recent enactments affecting the provisions in this title include the Hazardous Materials Transportation Authorization Act of 1994, the Swift Rail Development Act of 1994, the Federal Rail-

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Revised Section	Source (U.S. Code)	Source (Statutes at Large)
60120(b)	49 App.:1679b(a)(2), 49 App.:2008(a)(2), 49 App.:1677(c).	1992, Pub.L. 102-508, § 211(b), 106 Stat. 3304.
60120(c)	49 App.:2006(c).	Aug. 12, 1968, Pub.L. 90-481, § 10(c), 82 Stat. 725; Nov. 30, 1979, Pub.L. 96-129, §§ 104(a)(1), 152(a), 93 Stat. 992, 999.

In subsection (a)(1), the text of 49 App.:1677(b)(2) and 2006(b)(2) and the words "shall have jurisdiction to determine such actions" in 49 App.:1679b(a)(1) and 2008(a)(1) are omitted as redundant and because of 28:1331 and 1345. The word "civil" is added for consistency in the revised title and with other titles of the United States Code and because of rule 2 of the Federal Rules of Civil Procedure (28 App. U.S.C.). The words "to enforce this chapter" are substituted for "for equitable relief to redress or restrain a violation by any person of a provision of this chapter" to eliminate unnecessary words. The word "prescribed" is substituted for "issued" for consistency in the revised title and with other titles of the Code. The words "necessary or ... mandatory or prohibitive injunctive relief, interim equitable relief, and" are omitted as surplus.

In subsection (a)(2), the words "the Attorney General may bring a civil action in a district court of the United States" are substituted for "such district court shall, upon the request of the Attorney General

... have jurisdiction to issue to such person an order" for clarity and consistency and because of 28:1331 and 1345. The words "contumacy or" are omitted as surplus. The word "premises" is added for clarity and consistency. The words "or examine" are omitted as being included in "inspect".

In subsection (b), the words "mandatory or prohibitive" are omitted as surplus. The words "the defendant may demand a jury trial" are substituted for "trial shall be by the court or, upon demand of the accused, by a jury" to eliminate unnecessary words and for consistency in the revised title and with other titles of the Code.

In subsection (c), the words "common law or statutory" are omitted as surplus. House Report No. 103-180.

References in Text

Rule 42(b) of the Federal Rules of Criminal Procedure, referred to in subsection (b), is classified to Title 18, Federal Rules of Criminal Procedure. See Fed. Rules Crim.Proc. Rule 42, 18 USCA.

LIBRARY REFERENCES

American Digest System

Gas mains, pipes, and appliances, see Gas § 9.

Encyclopedias

Regulation and control of gas in general, see C.J.S. Gas § 3.

WESTLAW ELECTRONIC RESEARCH

Gas cases: 190k[add key number].

See, also, WESTLAW guide following the Explanation pages of this volume.

NOTES OF DECISIONS

Preemption 1 Private right of action 2

State regulation or control 1

1. **State regulation or control**
Federal law did not preempt property owners' claims under Louisiana law.

against contractor for natural gas pipeline reconditioning project, seeking remediation damages after project; there was no federal preemption of claims by Natural Gas Act or by Natural Gas Pipeline Safety Act. *Abramson v. Florida Gas Transmission Co.*, E.D.La. 1995, 909 F.Supp. 410.

2. Private right of action

Natural Gas Pipeline Safety Act did not create private right of action in poultry company plant employees injured in explosion allegedly caused by negligence in 753.

manufacture, installation, maintenance and operation of city's natural gas supply system against city which owned and operated local distribution system, manufacturer of safety regulating device, and installer of same where statute was silent as to such action, other remedies were available to adequately guard the right asserted, and private enforcement would not necessarily further the congressional policy of the Act. *Doak v. City of Clayton, Georgia*, S.D.Ga.1975, 390 F.Supp. 753.

§ 60121. Actions by private persons

(a) **General authority.**—(1) A person may bring a civil action in an appropriate district court of the United States for an injunction against another person (including the United States Government and other governmental authorities to the extent permitted under the 11th amendment to the Constitution) for a violation of this chapter or a regulation prescribed or order issued under this chapter. However, the person—

(A) may bring the action only after 60 days after the person has given notice of the violation to the Secretary of Transportation or to the appropriate State authority (when the violation is alleged to have occurred in a State certified under section 60105 of this title) and to the person alleged to have committed the violation;

(B) may not bring the action if the Secretary or authority has begun and diligently is pursuing an administrative proceeding for the violation; and

(C) may not bring the action if the Attorney General of the United States, or the chief law enforcement officer of a State, has begun and diligently is pursuing a judicial proceeding for the violation.

(2) The Secretary shall prescribe the way in which notice is given under this subsection.

(3) The Secretary, with the approval of the Attorney General, or the Attorney General may intervene in an action under paragraph (1) of this subsection.

(b) **Costs and fees.**—The court may award costs, reasonable expert witness fees, and a reasonable attorney's fee to a prevailing plaintiff in a civil action under this section. The court may award costs to a prevailing defendant when the action is unreasonable, frivolous, or meritless. In this subsection, a reasonable attorney's fee is a fee—

(1) based on the actual time spent and the reasonable expenses of the attorney for legal services provided to a person under this section; and

(2) computed at the rate prevailing for providing similar services for actions brought in the court awarding the fee.

(c) **State violations as violations of this chapter.**—In this section, a violation of a safety standard or practice of a State is deemed to be a violation of this chapter or a regulation prescribed or order issued under this chapter only to the extent the standard or practice is not more stringent than a comparable minimum safety standard prescribed under this chapter.

(d) **Additional remedies.**—A remedy under this section is in addition to any other remedies provided by law. This section does not restrict a right to relief that a person or a class of persons may have under another law or at common law.

(Added Pub.L. 103-272, § 1(e), July 5, 1994, 108 Stat. 1324.)

HISTORICAL AND STATUTORY NOTES

Revision Notes and Legislative Reports 1994 Acts.

Revised Section	Source (U.S. Code)	Source (Statutes at Large)
60121(a)(1)	49 App.:1686(a), (b) (1st sentence).	Aug. 12, 1968, Pub.L. 90-481, 82 Stat. 720, § 19; added Oct. 11, 1976, Pub.L. 94-477, § 8, 90 Stat. 2075; Nov. 30, 1979, Pub.L. 96-129, § 104(b), 93 Stat. 992; Nov. 30, 1979, Pub.L. 96-129, § 215, 93 Stat. 1014.
60121(a)(2)	49 App.:2014(a), (b) (1st sentence). 49 App.:1686(b) (last sentence). 49 App.:2014(b) (last sentence). 49 App.:1686(c). 49 App.:2014(c). 49 App.:1686(e). 49 App.:2014(e). 49 App.:1686(f). 49 App.:2014(f). 49 App.:1686(d).	
60121(a)(3)	49 App.:1686(c).	
60121(b)	49 App.:2014(c).	
60121(c)	49 App.:2014(e).	
60121(d)	49 App.:1686(d).	

In subsection (a)(1), before clause (A), the text of 49 App.:1686(a)(last sentence, words after the comma) and 2014(a)(last sentence, words after the comma) is omitted as surplus because the amount in controversy is no longer a criterion. The word "bring" is substituted for "commence" for consistency in the revised title and with other titles of the United States Code. The words "mandatory or prohib-

itive", "including interim equitable relief", "State, municipality, or", and "legged to be" are omitted as surplus. The word "prescribed" is added for consistency in the revised title and with other titles of the Code.

In subsection (a)(2), the words "by regulation" are omitted as surplus because of 49:322(a).

In subsection (a)(3), the words "as a matter of right" are omitted as surplus.

In subsection (b), before clause (1), the words "in the interest of justice" and "of suit, including" are omitted as surplus.

In clause (1), the words "by an attorney" and "advice and other" are omitted as surplus. The words "provided to a person under this section" are substituted for "providing ... in connection with representing a person in an action

brought under this section" to eliminate unnecessary words.

In subsection (c), the word "Federal" is omitted as surplus. The words "prescribed under this chapter" are added for clarity.

In subsection (d), the words "enforcement of this chapter or any order or regulation under this chapter or to seek any other" are omitted as surplus.

House Report No. 103-180.

LIBRARY REFERENCES

American Digest System

Gas mains, pipes, and appliances, see Gas §9.

Subjects of injunctions; protection of public in general, see Injunction §89(1).

Encyclopedias

Regulation and control of gas in general, see C.J.S. Gas § 3.

Subjects of injunctions; public safety, health, and convenience generally, see C.J.S. Injunctions § 134.

WESTLAW ELECTRONIC RESEARCH

Gas cases: 190k[add key number].

Injunction cases: 212k[add key number].

See, also, WESTLAW guide following the Explanation pages of this volume.

NOTES OF DECISIONS

Attorney fees 3

Diligent pursuit of administrative proceedings 2
Notice 1

1. Notice

Amended complaint under the Hazardous Liquid Pipeline Safety Act filed more than 60 days after detailed notice of alleged violations had been given to the Department of Transportation cured any defects in initial compliance with notice requirements of citizen suit provisions of the Act. *Williams Pipe Line Co. v. City of Mounds View, Minn.*, D.Minn.1987, 651 F.Supp. 551.

2. Diligent pursuit of administrative proceedings

Office of Pipeline Safety's continuous enforcement actions following leak and resulting explosion of gasoline pipeline was "diligent pursuit" of administrative proceedings under Hazardous Liquid Pipeline Safety Act, precluding city from

bringing citizen's suit under Act seeking injunction requiring pipeline's removal or replacement; although city claimed that OPS had not responded adequately to possibility that accident was caused by corrosion of pipeline, OPS had required extensive testing of pipeline's safety, restricted pipeline's operations, and imposed large civil penalty upon pipeline company. *Williams Pipe Line Co. v. City of Mounds View, Minn.*, D.Minn.1989, 704 F.Supp. 914.

3. Attorney fees

Attorney fees for appeals were not recoverable under Natural Gas Pipeline Safety Act, where case involved federal question and pendent state law claims, where appeal was limited to state law claims, and where no Texas statute authorized award of fees for common-law trespass action that was appealed. *Hamman v. Southwestern Gas Pipeline, Inc.*, C.A.5 (Tex.) 1987, 832 F.2d 55.

§ 60122. Civil penalties

(a) **General penalties.**—(1) A person that the Secretary of Transportation decides, after written notice and an opportunity for a

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§ 191.25

stress of 20 percent or more of its specified minimum yield strength.

(5) Any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices.

(6) A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency.

(7) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

(8) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes gas or LNG.

(b) A report is not required for any safety-related condition that—

(1) Exists on a master meter system or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline (other than an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

[Amdt. 191-6, 53 FR 24949, July 1, 1988, as amended by Amdt. 191-14, 63 FR 37501, July 13, 1998]

§ 191.25 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a) must be filed

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(received by the Associate Administrator, OPS) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by facsimile at (202) 366-7128.

(b) The report must be headed "Safety-Related Condition Report" and provide the following information:

(1) Name and principal address of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

[Amdt. 191-6, 53 FR 24949, July 1, 1988; 53 FR 29800, Aug. 8, 1988, as amended by Amdt. 191-7, 54 FR 32344, Aug. 7, 1989; Amdt. 191-3, 54 FR 40878, Oct. 4, 1989; Amdt. 191-10, 61 FR 18516, Apr. 26, 1996]

§ 191.27 Filing offshore pipeline condition reports.

(a) Each operator shall, within 60 days after completion of the inspection of all its underwater pipelines subject to § 192.612(a), report the following information:

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Subpart C—Pipe Design

- (1) Name and principal address of operator.
- (2) Date of report.
- (3) Name, job title, and business telephone number of person submitting the report.
- (4) Total length of pipeline inspected.
- (5) Length and date of installation of each exposed pipeline segment, and location, including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.
- (6) Length and date of installation of each pipeline segment, if different from a pipeline segment identified under paragraph (a)(6) of this section, that is a hazard to navigation, and the location, including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.
- (b) The report shall be mailed to the Information Officer, Research and Special Programs Administration, Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590.

[Amdt. 191-9, 56 FR 63770, Dec. 5, 1991, as amended by Amdt. 191-14, 63 FR 37501, July 13, 1998]

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS**Subpart A—General**

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- 192.3 Definitions.
- 192.5 Class locations.
- 192.7 Incorporation by reference.
- 192.9 Gathering lines.
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AUTHORITY: 49 U.S.C. 5103, 60102, 60104, 60106, 60109, 60110, 60113, and 60116; and 49 CFR 1.53.
SOURCE: 35 FR 13257, Aug. 19, 1970, unless otherwise noted.

Subpart A—General**\$ 192.1 Scope of part.**

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the

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transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to:

(1) Offshore pipelines upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(2) Onshore gathering of gas outside of the following areas:

(i) An area within the limits of any incorporated or unincorporated city, town, or village.

(ii) Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.

(3) Onshore gathering of gas within inlets of the Gulf of Mexico except as provided in § 192.612.

(4) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(i) Fewer than 10 customers, if no portion of the system is located in a public place; or

(ii) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

(5) On the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-67, 56 FR 63771, Dec. 5, 1991; Amdt. 192-78, 61 FR 28782, June 6, 1996; Amdt. 192-81, 62 FR 61685, Nov. 19, 1997]

§ 192.3 Definitions.

As used in this part:

Abandoned means permanently removed from service.

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

Distribution line means a pipeline other than a gathering or transmission line.

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Exposed pipeline means a pipeline where the top of the pipe is protruding above the seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to navigation means, for the purpose of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Listed specification means a specification listed in section I of appendix B of this part.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

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meter that measures the transfer of gas from an operator to a consumer.

SMYS means specified minimum yield strength is:

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107(b).

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Transmission line means a pipeline, other than a gathering line, that:

(a) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;

(b) Operates at a hoop stress of 20 percent or more of SMYS; or

(c) Transports gas within a storage field. A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

[Amdt. 192-13, 38 FR 9084, Apr. 10, 1973, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-67, 56 FR 63771, Dec. 5, 1991; Amdt. 192-72, 59 FR 17281, Apr. 12, 1994; Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-81, 62 FR 61685, Nov. 19, 1997; Amdt. 192-85, 63 FR 37501, July 13, 1998; Amdt. 192-89, 65 FR 54, Sept. 8, 2000]

EFFECTIVE DATE NOTE: At 65 FR 54443, Sept. 8, 2000, § 192.3 was amended by adding the definition of "Abandoned", effective Oct. 10, 2000.

§ 192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

(1) A "class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1- mile (1.6 kilometers) length of pipeline.

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(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

- (i) A Class 1 location is:
 - (1) An offshore area; or
 - (2) Any class location unit that has 10 or fewer buildings intended for human occupancy.
- (ii) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

- (i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

- (1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.
- (2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

[Amdt. 192-78, 61 FR 28783, June 6, 1996; 61 FR 35139, July 5, 1996, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.7 Incorporation by reference.

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this part.

(b) All incorporated materials are available for inspection in the Research and Special Programs Administration, 400 Seventh Street, SW., Wash-

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ington, DC, and at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, the incorporated materials are available from the respective organizations listed in appendix A to this part.

(c) The full titles for the publications incorporated by reference in this part are provided in appendix A to this part. Numbers in parentheses indicate applicable editions. Earlier editions of documents listed or editions of documents formerly listed in previous editions of appendix A may be used for materials and components manufactured, designed, or installed in accordance with those earlier editions or earlier documents at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR for a listing of the earlier listed editions or documents.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; Amdt. 192-51, 51 FR 15334, Apr. 23, 1986; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.9 Gathering lines.

Except as provided in §§ 192.1 and 192.150, each operator of a gathering line must comply with the requirements of this part applicable to transmission lines.

[Amdt. 192-72, 59 FR 17281, Apr. 12, 1994]

§ 192.10 Outer continental shelf pipelines.

Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act; 43 U.S.C. 1331) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict

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plans, procedures, and programs that it is required to establish under this part. [35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.14 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with subpart J of this part to substantiate the maximum allowable operating pressure permitted by subpart L of this part.

(b) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.15 Rules of regulatory construction.

(a) As used in this part: *Includes* means including but not limited to.

May means "is permitted to" or "is authorized to".

May not means "is not permitted to" or "is not authorized to".

Shall is used in the mandatory and imperative sense.

(b) In this part:

the transfer point on a schematic located near the transfer point. If a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to RSPA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Amdt. 192-81, 62 FR 61695, Nov. 19, 1997]

§ 192.11 Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and ANSI/NFPA 58 and 59.

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and ANSI/NFPA 58 and 59, ANSI/NFPA 58 and 59 prevail.

[Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.13 General.

(a) No person may operate a segment of pipeline that is readied for service after March 12, 1971, or in the case of an offshore gathering line, after July 31, 1977, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part in accordance with § 192.14.

(b) No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed after November 12, 1970, or in the case of an offshore gathering line, after July 31, 1977, unless that replacement, relocation, or change has been made in accordance with this part.

(c) Each operator shall maintain, modify as appropriate, and follow the

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- (1) Words importing the singular include the plural;
- (2) Words importing the plural include the singular; and
- (3) Words importing the masculine gender include the feminine.

§ 192.16 Customer notification.

(a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to § 192.465 if the customer's buried piping is metallic, survey for leaks according to § 192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.

(b) Each operator shall notify each customer once in writing of the following information:

(1) The operator does not maintain the customer's buried piping.

(2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.

(3) Buried gas piping should be—

- (i) Periodically inspected for leaks;
- (ii) Periodically inspected for corrosion if the piping is metallic; and
- (iii) Repaired if any unsafe condition is discovered.

(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

(5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

(c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators

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of master meter systems may continuously post a general notice in a prominent location frequented by customers.

(d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

- (1) A copy of the notice currently in use; and
- (2) Evidence that notices have been sent to customers within the previous 3 years.

[Amdt. 192-74, 60 FR 41828, Aug. 14, 1995, as amended by Amdt. 192-74A, 60 FR 63451, Dec. 11, 1995; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998]

Subpart B—Materials**§ 192.51 Scope.**

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

§ 192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

- (i) Section II of appendix B to this part; or
- (ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

- (1) It was manufactured in accordance with a listed specification and it

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meets the requirements of paragraph II-C of appendix B to this part;

(2) It meets the requirements of:

- (i) Section II of appendix B to this part; or
- (ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Specification 5L.

§ 192.61 [Reserved]**§ 192.63 Marking of materials.**

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

- (1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D 2513; or
- (2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

- (1) The item is identifiable as to type, manufacturer, and model.

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(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-31, 43 FR 883, Apr. 3, 1978; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; Amdt. 192-61A, 54 FR 32642, Aug. 9, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-76, 61 FR 26122, May 24, 1996; 61 FR 36826, July 15, 1996]

§ 192.65 Transportation of pipe.

In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless:

- The transportation is performed in accordance with API RP 5L1.
- In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[Amdt. 192-12, 38 FR 4761, Feb. 22, 1973, as amended by Amdt. 192-17, 40 FR 6346, Feb. 11, 1975; 58 FR 14521, Mar. 18, 1993]

Subpart C—Pipe Design

§ 192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.

§ 192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§ 192.105 Design formula for steel pipe.

- The design pressure for steel pipe is determined in accordance with the following formula:

$P = (2 S/D) \times F \times E \times T$
P=Design pressure in pounds per square inch (kPa) gauge.

S=Yield strength in pounds per square inch (kPa) determined in accordance with § 192.107.

D=Nominal outside diameter of the pipe in inches (millimeters).

t=Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with § 192.109. Additional wall thickness required for concurrent external loads in accordance with § 192.103 may not be included in computing design pressure.

F=Design factor determined in accordance with § 192.111.

E=Longitudinal joint factor determined in accordance with § 192.113.

T=Temperature derating factor determined in accordance with § 192.115.

- If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900° F (482° C) at any time or is held above 600° F (316° C) for more than 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-47, 49 FR 7569, Mar. 1, 1984; Amdt. 192-46, 63 FR 37502, July 13, 1998]

§ 192.107 Yield strength (S) for steel pipe.

- For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.

- For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:

- If the pipe is tensile tested in accordance with section II-D of appendix B to this part, the lower of the following:
 - 80 percent of the average yield strength determined by the tensile tests.
 - The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 p.s.i. (165 MPa).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 26783, June 6, 1996; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.109 Nominal wall thickness (t) for steel pipe.

- If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

- However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in § 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.111 Design factor (F) for steel pipe.

- Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

	Class location	Design factor (F)
1	0.72
2	0.60
3	0.50

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.80

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(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 p.s.i. (165 MPa).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 26783, June 6, 1996; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.113 Longitudinal joint factor (E) for steel pipe.

- The longitudinal joint factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

- Steel pipe in a compressor station, regulating station, or measuring station; and
 - Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.
- [35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.113 Longitudinal joint factor (E) for steel pipe.

- The longitudinal joint factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.80

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Electric resistance welded	1.00
	Double submerged arc welded	1.00
ASTM A 381	Electric fusion-welded	1.00
ASTM A 671	Electric fusion-welded	1.00
ASTM A 672	Electric fusion-welded	1.00
ASTM A 691	Seamless	1.00
API 5L	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	1.00
Other	Pipe over 4 inches (102 millimeters) or less	.80
Other	Pipe 4 inches (102 millimeters) or less	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

[Amdt. 192-37, 46 FR 10159, Feb. 2, 1981, as amended by Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.115 Temperature derating factor (7) for steel pipe.

The temperature derating factor to be used in the design formula in § 192.105 is determined as follows:

Gas temperature in degrees Fahrenheit (°F)	Temperature derating factor (T)
250°F (121°C) or less	1.000
300°F (149°C)	0.967
350°F (177°C)	0.933
400°F (204°C)	0.900
450°F (232°C)	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.117 [Reserved]

§ 192.119 [Reserved]

§ 192.121 Design of plastic pipe.

Subject to the limitations of § 192.123, the design pressure for plastic pipe is determined in accordance with either of the following formulas:

§ 192.123 Design limitations for plastic pipe.

- (a) The design pressure may not exceed a gauge pressure of 689 kPa (100 psig) for plastic pipe used in:
- (1) Distribution systems; or
 - (2) Classes 3 and 4 locations.
- (b) Plastic pipe may not be used where operating temperatures of the pipe will be:

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(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i. (689 kPa) gage.

(d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft³ (6.9/m³) under standard conditions. Standard conditions refers to 60°F and 14.7 psia (15.6°C and one atmosphere) of gas.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-82, 54 FR 5628, Feb. 6, 1989; Amdt. 192-85, 63 FR 37502, July 13, 1998]

Subpart D—Design of Pipeline Components

§ 192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§ 192.143 General requirements.

Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

[Amdt. 48, 49 FR 19824, May 10, 1984]

§ 192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in appendix A of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

- (a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair

Nominal size in inches (millimeters).	Minimum wall thickness in inches (millimeters).
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-31, 43 FR 13883, Apr. 3, 1978; Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.125 Design of copper pipe.

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

(b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard size inch (millimeter)	Nominal O.D. inch (millimeter)	Wall thickness inch (millimeter)	
		Nominal	Tolerance
1/2 (13)	.625 (16)	.040 (1.02)	.0035 (.0889)
3/4 (19)	.750 (19)	.042 (1.07)	.0035 (.0889)
1 (25)	.875 (22)	.045 (1.14)	.004 (.102)
1 1/4 (32)	1.125 (29)	.050 (1.27)	.004 (.102)
1 1/2 (38)	1.375 (35)	.055 (1.40)	.0045 (.1143)
2 (51)	1.625 (41)	.060 (1.52)	.0045 (.1143)

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(a) The strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in appendix A:

- (1) Pressure testing;
- (2) Materials; and
- (3) Pressure and temperature ratings.

[Amdt. 192-45, 48 FR 30639, July 5, 1983]

§ 192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements, or equivalent, of API 6D. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

- (1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.
- (2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

- (1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and
- (2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5, MSS SP-44, or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993]

§ 192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

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§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each line section of a transmission line where the line pipe, valve, fitting, or other line component is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to:

- (1) Manifolds;
- (2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Offshore pipelines, other than transmission lines 10 inches (254 millimeters) or greater in nominal diameter, that transport gas to onshore facilities; and

(8) Other piping that, under § 190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under § 190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow

passage of instrumented internal inspection devices.

[Amdt. 192-72, 59 FR 17281, Apr. 12, 1994, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that:

- (1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and
- (2) A 1½-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.153 Components fabricated by welding.

(a) Except for branch connection and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

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- (1) Regularly manufactured butt-welding fittings.
- (2) Pipe that has been produced and tested under a specification listed in appendix B to this part.
- (3) Partial assemblies such as split rings or collars.
- (4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192-68, 58 FR 45288, Aug. 27, 1993; Amdt. 192-86, 63 FR 37502, July 13, 1998]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or compo-

nents, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

- (1) Prevent undue strain on connected equipment;
- (2) Resist longitudinal forces caused by a bend or offset in the pipe; and
- (3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

- (1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.
- (2) Provision must be made for the service conditions involved.
- (3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

- (1) A structural support may not be welded directly to the pipe.
- (2) The support must be provided by a member that completely encircles the pipe.
- (3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header

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and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-68, 53 FR 1635, Jan. 21, 1988]

§ 192.163 Compressor stations: Design and construction.

(a) *Location of compressor building.* Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either—

- (1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or
- (2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

(d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be operable from the inside without a key.

(e) *Electrical facilities.* Electrical equipment and wiring installed in com-

pressor stations must conform to the National Electrical Code, ANSI/NFPA 70, so far as that code is applicable.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, 37503, July 13, 1998]

§ 192.165 Compressor stations: Liquid removal.

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must:

- (1) Have a manually operable mean of removing these liquids.
- (2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and
- (3) Be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

§ 192.167 Compressor stations: Emergency shutdown.

(a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

- (1) It must be able to block gas out of the station and blow down the static piping.
- (2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.
- (3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that:

- (i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

installation as required by subpart J of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles (4 kilometers) of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow

$C = (D \times P \times F / 48.33)$ ($C = (3D \times P \times F / 1,000)$)

in which:

C = Minimum clearance between pipe containers or bottles in inches (millimeters).

D = Outside diameter of pipe containers or bottles in inches (millimeters).

P = Maximum allowable operating pressure, p.s.i. (kPa) gage.

F = Design factor as set forth in § 192.111 of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) gage or more	100 (31)

(2) Designed using the design factors set forth in § 192.111; and

(3) Buried with a minimum cover in accordance with § 192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A 372/A 372M.

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermite welding process is used.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor stations: Additional safety equipment.

(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

(e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor stations: Ventilation.

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

§ 192.175 Pipe-type and bottle-type holders.

(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

(i) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least two locations, each of which is:

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet (153 meters) from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station:

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building:

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility which conforms to Class I, Group D, of the National Electrical Code is not a source of ignition.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.169 Compressor stations: Pressure limiting devices.

(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

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of gas to an offshore platform in an emergency.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

- (1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.
- (2) The operating stem or mechanism must be readily accessible.
- (3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Valves: Structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the

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opening and to avert strains in the pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as practical, away from:

- (a) Street intersections or points where traffic is heavy or dense;
- (b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
- (c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

(a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

- (1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;
- (2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
- (3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

- (1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;
- (2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings

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and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.189 Vaults: Drainage and water-proofing.

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) Electrical equipment in vaults must conform to the applicable requirements of Class I, Group D, of the National Electrical Code, ANSI/NFPA 70.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-76, 61 FR 26122, May 24, 1996]

§ 192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517.

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§ 192.195 Protection against accidental overpressuring.

(a) *General requirements.* Except as provided in § 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.

(b) *Additional requirements for distribution systems.* Each distribution system

that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

- (1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and
- (2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is under 60 p.s.i. (414 kPa) gage and a service regulator having the following characteristics is used, no other pressure limiting device is required:

- (1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.
- (2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.
- (3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of

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service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the

regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

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§ 192.203 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-9, 37 FR 20827, Oct. 4, 1972; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.203 Instrument, control, and sampling pipe and components.

(a) *Applicability.* This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) *Materials and design.* All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from a source of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400° F (204°C).

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator

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and the over-pressure protective device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

Subpart E—Welding of Steel in Pipelines

§ 192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§ 192.225 Welding—General.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

[Amdt. 192-52, 51 FR 20297, June 4, 1986]

§ 192.227 Qualification of welders.

(a) Except as provided in paragraph (b) of this section, each welder must be qualified in accordance with section 3 of API Standard 1104 or section IX of the ASME Boiler and Pressure Vessel Code. However, a welder qualified under an earlier edition than listed in appendix A may weld but may not re-qualify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix

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C of this part as a requirement of the qualifying test.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-52, 51 FR 20297, June 4, 1986; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.229 Limitations on welders.

(a) No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process.

(c) A welder qualified under § 192.227(a)—

- (1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under section 3 or 6 of API Standard 1104, except that a welder qualified under an earlier edition previously listed in Appendix A of this part may weld but may not re-qualify under that earlier edition; and
- (2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder qualified under § 192.227(b) may not weld unless—

- (1) Within the preceding 15 calendar months, but at least once each calendar year, the welder has requalified under § 192.227(b); or
- (2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder has had—
 - (i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or
 - (ii) For welders who work only on service lines 2 inches (51 millimeters) or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

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(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.243 Nondestructive testing.

(a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

(b) Nondestructive testing of welds must be performed:

- (1) In accordance with written procedures; and
- (2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under § 192.241(c).

(d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

- (1) In Class 1 locations, except offshore, at least 10 percent.
- (2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

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(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).

(f) When nondestructive testing is required under § 192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-50, 50 FR 37192, Sept. 12, 1985; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under § 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under § 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 192-46, 46 FR 48674, Oct. 20, 1983]

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Subpart F—Joining of Materials Other Than by Welding

§ 192.271 Scope.

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§ 192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.277 Ductile iron pipe.

(a) Ductile iron pipe may not be joined by threaded joints.

(b) Ductile iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

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(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-34, 44 FR 42973, July 23, 1979; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.283 Plastic pipe: qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—
(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure (Quick Burst)) of ASTM D 2513;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517; or

(iii) In the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM Designation F1055.

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and
(3) For procedures intended for non-lateral pipe connections, follow the

§ 192.279 Copper pipe.

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192-62, 54 FR 5628, Feb. 6, 1989, as amended at 58 FR 14521, Mar. 18, 1993]

§ 192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM Designation D 2513.

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM Designation D 2517.

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tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) **Mechanical joints.** Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

- (1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning).
- (2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.
- (3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.
- (4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.
- (5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100°F (38°C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.
- (6) Each specimen that fails at the grips must be retested using new pipe.
- (7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.
- (c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.
- (d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the

his system is qualified in accordance with this section.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981]

§ 192.287 Plastic pipe: inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192-34, 44 FR 42974, July 23, 1979]

Subpart G—General Construction Requirements for Transmission Lines and Mains

§ 192.301 Scope.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

§ 192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

§ 192.305 Inspection: General.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

§ 192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

§ 192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

- (1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

- (1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.
- (2) A dent that affects the longitudinal weld or a circumferential weld.
- (3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

- (i) More than ¼ inch (6.4 millimeters) in pipe 12½ inches (324 millimeters) or less in outer diameter; or
- (ii) More than 2 percent of the nominal pipe diameter in pipe over 12½ inches (324 millimeters) in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

- (1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
- (2) The nominal wall thickness required for the design pressure of the pipeline.
- (d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.
- (e) Each gouge, groove, arc burn, or dent that is removed from a length of

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pipe must be removed by cutting out the damaged portion as a cylinder.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999]

§ 192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired by a patching saddle or removed.

§ 192.313 Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with § 192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

[Amdt. No. 192-26, 41 FR 26018, June 24, 1976, as amended by Amdt. 192-29, 42 FR 42866, Aug. 25, 1977; Amdt. 192-29, 42 FR 60148, Nov. 25, 1977; Amdt. 192-49, 50 FR 13225, Apr. 3, 1985; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

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(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1½° for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

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(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative above-ground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an uncased casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of

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this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in § 192.175(b).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil	Consolidated rock
Inches (Millimeters):		
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

- (1) Establishes a minimum cover of less than 24 inches (610 millimeters);
- (2) Requires that mains be installed in a common trench with other utility lines; and
- (3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

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(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in § 192.3, must be installed in accordance with § 192.612(b)(3).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34906, Aug. 16, 1976; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

Subpart H—Customer Meters, Service Regulators, and Service Lines**§ 192.351 Scope.**

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914

Research and Special Programs Administration, DOT**§ 192.361****§ 192.359 Customer meter installations: Operating pressure.**

(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.361 Service lines: Installation.

(a) *Depth.* Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:

- (1) In the case of a metal service line, be protected against corrosion;
- (2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

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(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building:

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.363 Service lines: Valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service lines: Location of valves.

(a) *Relation to regulator or meter.* Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) *Underground valves.* Each underground service-line valve must be lo-

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cated in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§ 192.367 Service lines: General requirements for connections to main piping.

(a) *Location.* Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) *Compression-type connection to main.* Each compression-type service line to main connection must:

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of § 192.273.

(b) If a threaded tap is being inserted, the requirements of § 192.151 (b) and (c) must also be met.

§ 192.371 Service lines: Steel.

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

Research and Special Programs Administration, DOT**§ 192.381****§ 192.381 Service lines: Excess flow valve performance standards.**

(a) Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

(i) Close at, or not more than 50 per cent above, the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow—

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance

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activities on the service, such as blowing liquids from the line.

[Amdt. 192-79, 61 FR 31459, June 20, 1996, as amended by Amdt. 192-80, 62 FR 2619, Jan. 17, 1997; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.383 Excess flow valve customer notification.

(a) *Definitions.* As used in this section:

Costs associated with installation means the costs directly connected with installing an excess flow valve, for example, costs of parts, labor, inventory and procurement. It does not include maintenance and replacement costs until such costs are incurred.

Replaced service line means a natural gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line customer means the person who pays the gas bill, or where service has not yet been established, the person requesting service.

(b) *Which customers must receive notification.* Notification is required on each newly installed service line or replaced service line that operates continuously throughout the year at a pressure not less than 68.9 kPa (10 psig) and that serves a single residence. On these lines an operator of a natural gas distribution system must notify the service line customer once in writing.

(c) *What to put in the written notice.* (1) An explanation for the customer that an excess flow valve meeting the performance standards prescribed under § 192.381 is available for the operator to install if the customer bears the costs associated with installation; (2) An explanation for the customer of the potential safety benefits that may be derived from installing an excess flow valve. The explanation must include that an excess flow valve is designed to shut off flow of natural gas automatically if the service line breaks;

(3) A description of installation, maintenance, and replacement costs. The notice must explain that if the customer requests the operator to install an EFV, the customer bears all costs associated with installation, and what those costs are. The notice must alert the customer that the costs for

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maintaining and replacing an EFV may later be incurred, and what those costs will be, to the extent known.

(d) *When notification and installation must be made.* (1) After February 3, 1999 an operator must notify each service line customer set forth in paragraph (b) of this section:

(i) On new service lines when the customer applies for service.

(ii) On replaced service lines when the operator determines the service line will be replaced.

(2) If a service line customer requests installation an operator must install the EFV at a mutually agreeable date.

(e) *What records are required.* (1) An operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

(i) A copy of the notice currently in use; and

(ii) Evidence that notice has been sent to the service line customers set forth in paragraph (b) of this section, within the previous three years.

(2) [Reserved]

(f) *When notification is not required.* The notification requirements do not apply if the operator can demonstrate—

(1) That the operator will voluntarily install an excess flow valve or that the state or local jurisdiction requires installation;

(2) That excess flow valves meeting the performance standards in § 192.381 are not available to the operator;

(3) That the operator has prior experience with contaminants in the gas stream that could interfere with the operation of an excess flow valve, cause loss of service to a residence, or interfere with necessary operation or maintenance activities, such as blowing liquids from the line.

(4) That an emergency or short time notice replacement situation made it impractical for the operator to notify a service line customer before replacing a service line. Examples of these situations would be where an operator has to replace a service line quickly because of—

(i) Third party excavation damage;

(ii) Grade 1 leaks as defined in the Appendix G-192-11 of the Gas Piping

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Technology Committee guide for gas transmission and distribution systems; (iii) A short notice service line relocation request.

[Amdt. 192-82, 63 FR 5471, Feb. 3, 1998; Amdt. 192-83, 63 FR 20135, Apr. 23, 1998]

Subpart I—Requirements for Corrosion Control

SOURCE: Amdt. 192-4, 36 FR 12302, June 30, 1971, unless otherwise noted.

§ 192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

§ 192.452 Applicability to converted pipelines.

Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with § 192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.453 General.

The corrosion control procedures required by § 192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994]

§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of § 192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must

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be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192-28, 42 FR 35654, July 11, 1977; Amdt. 192-39, 47 FR 9844, Mar. 8, 1982; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

- (1) Bare or ineffectively coated transmission lines.
- (2) Bare or coated pipes at compressor, regulator, and measuring stations.

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(3) Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

(c) For the purpose of this subpart, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 38390, Sept. 5, 1978]

§ 192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under §§ 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Amdt. 192-87, 64 FR 56981, Oct. 22, 1999]

§ 192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

- (1) Be applied on a properly prepared surface;
- (2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
- (3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

- (5) Have properties compatible with any supplemental cathodic protection.
- (b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

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(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by paragraphs (b) and (c) of § 192.455 and paragraph (b) of § 192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 38390, Sept. 5, 1978; Amdt. 192-35A, 45 FR 23441, Apr. 7, 1980; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

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(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192-27, 41 FR 34006, Aug. 16, 1976]

§ 192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material

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compatible with the pipe coating and the insulation on the wire.

§ 192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m³) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means

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of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.479 Atmospheric corrosion control: General.

(a) Pipelines installed after July 31, 1971. Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.

(b) Pipelines installed before August 1, 1971. Each operator having an aboveground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall—

(1) Determine the areas of atmospheric corrosion on the pipeline;

(2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

(3) Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.491 Atmospheric corrosion control: Monitoring.

After meeting the requirements of § 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and at least once each calendar year, but with intervals not exceeding 15 months, for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.483 Remedial measures: General.
(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of § 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§ 192.485 Remedial measures: Transmission lines.

(a) General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with R5TRENG disk). Both procedures apply to corroded regions that do not penetrate the

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pipe wall, subject to the limitations prescribed in the procedures.

(Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-83, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-88, 64 FR 68664, Dec. 14, 1999)

§ 192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

(Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-88, 64 FR 68665, Dec. 14, 1999)

§ 192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) *General graphitization.* Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) *Localized graphitization.* Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to

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the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§ 192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

(Amdt. 192-78, 61 FR 28785, June 6, 1996)

Subpart J—Test Requirements

§ 192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and § 192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is—

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in § 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	75	75
3	30	50

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factor of the component certifies that—

(1) The component was tested to at least the pressure required for the pipeline to which it is being added; or

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added.

(e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

(35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998)

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—

(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

(35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998)

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
4	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

(35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-60, 53 FR 36023, Sept. 16, 1988; Amdt. 192-60A, 54 FR 5485, Feb. 3, 1989)

§ 192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manu-

§ 192.509**§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.**

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.511 Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with § 192.507 of this subpart.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-74, 61 FR 16517, Apr. 26, 1996; Amdt. 192-45, 63 FR 37504, July 13, 1998]

§ 192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

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(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under § 192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 100°F (38°C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-77, 61 FR 27793, June 3, 1996; 61 FR 45905, Aug. 30, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.515 Environmental protection and safety requirements.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§ 192.517 Records.

Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:

- (a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
- (b) Test medium used.
- (c) Test pressure.
- (d) Test duration.

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- (e) Pressure recording charts, or other record of pressure readings.
- (f) Elevation variations, whenever significant for the particular test.
- (g) Leaks and failures noted and their disposition.

Subpart K—Upgrading**§ 192.551 Scope.**

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (upgrading) for pipelines.

§ 192.553 General requirements.

(a) *Pressure increases.* Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) *Records.* Each operator who upgrades a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the upgrading.

(c) *Written plan.* Each operator who upgrades a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location. However, when upgrading a steel pipeline, if any variable necessary to deter-

mine the design pressure under the design formula (§ 192.105) is unknown, the MAOP may be increased as provided in § 192.619(a)(1).

[35 FR 13257, Aug. 10, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.555 Upgrading to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

(1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

(2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under § 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1

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location if the line has not previously been tested, and if:

(1) It is impractical to test it in accordance with the requirements of this part;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

§ 192.557 Uprating: Steel pipelines to a pressure less than 30 percent of SMYS; plastic, cast iron, and ductile iron pipelines.

(a) Unless the requirements of this section have been met, no person may subject:

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored dur-

ing the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

(1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least

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three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at

Pipe size inches (millimeters)	Allowance inches (millimeters)		
	Cast iron pipe	Centrifugally cast pipe	Ductile iron pipe
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 MPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; Amdt. 195-35, 63 FR 37504, July 13, 1998]

Subpart L—Operations

§ 192.601 Scope.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

§ 192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall keep records necessary to administer the procedures established under § 192.605.

(c) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and

procedures as necessary to provide a reasonable level of safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-66, 56 FR 31090, July 9, 1991; Amdt. 192-71, 59 FR 6584, Feb. 11, 1994; Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations:

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.

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(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

(9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to

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provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) *Safety-related condition reports.*

The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 191.23 of this subchapter.

(e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§ 192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994, as amended by Amdt. 192-71A, 60 FR 14381, Mar. 17, 1995]

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§ 192.607 [Reserved]

§ 192.609 Change in class location: Required study.

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be ascertained from available records:

(d) The operating and maintenance history of the segment;

(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in

Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§ 192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed within 18 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 18-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

[Amdt. 192-63A, 54 FR 24174, June 6, 1989 as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

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§ 192.612 Underwater inspection and re-burial of pipelines in the Gulf of Mexico and its inlets.

(a) Each operator shall, in accordance with this section, conduct an underwater inspection of its pipelines in the Gulf of Mexico and its inlets. The inspection must be conducted after October 3, 1989 and before November 16, 1992.

(b) If, as a result of an inspection under paragraph (a) of this section, or upon notification by any person, an operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802 of the location, and, if available, the geographic coordinates of that pipeline;

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

[Amdt. 192-67, 56 FR 63771, Dec. 5, 1991, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.613 Continuing surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to re-

condition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with § 192.619 (a) and (b).

§ 192.614 Damage prevention program.

(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purposes of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

(b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under § 198.37 of this chapter; or

(2) The one-call system:

(i) Is operated in accordance with § 198.39 of this chapter;

(ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and

(iii) Assesses a participating pipeline operator a fee that is proportionate to

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the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as possible, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the

transportation of gas need not comply with the following:

(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and

(2) The requirements of paragraphs (c)(1) and (c)(2) of this section.

[Amdt. 192-40, 47 FR 13824, Apr. 1, 1982, as amended by Amdt. 192-57, 52 FR 32800, Aug. 31, 1987; Amdt. 192-73, 60 FR 14650, Mar. 20, 1995; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-82, 62 FR 61699, Nov. 19, 1997; Amdt. 192-84, 63 FR 38758, July 20, 1998]

§ 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible.

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(b) Each operator shall:

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

[Amdt. 192-24, 41 FR 13587, Mar. 31, 1976, as amended by Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.616 Public education.

Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

[Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

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49 CFR Ch. I (10-1-00 Edition)**§ 192.617 Investigation of failures.**

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under § 192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12 3/4 inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors ¹ , segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under § 192.14
1.....	1.1	1.1	1.25
2.....	1.25	1.25	1.25
3.....	1.4	1.5	1.5

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(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.

(2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of § 192.197(c).

(3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt 192-85, 63 FR 37504, July 13, 1998]

§ 192.623 Maximum and minimum allowable operating pressure; Low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low-pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

§ 192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily

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Class location	Factors ¹ , segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under § 192.14
4.....	1.4	1.5	1.5

¹For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or a subbottom in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested in accordance with paragraph (a)(2) of this section after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was uprated in accordance with subpart K of this part.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

(c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, or in the case of offshore gathering lines, July 1, 1976, subject to the requirements of § 192.611.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.619, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§ 192.621 Maximum allowable operating pressure: High-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

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detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

- (1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;
- (2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975:

- (i) An underground storage field;
- (ii) A gas processing plant;
- (iii) A gas dehydration plant; or
- (iv) An industrial plant using gas in a process where the presence of an odorant:

- (A) Makes the end product unfit for the purpose for which it is intended;
 - (B) Reduces the activity of a catalyst; or
 - (C) Reduces the percentage completion of a chemical reaction;
- (3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

- (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

- (1) The odorant may not be deleterious to persons, materials, or pipe.
- (2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

- (d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

- (f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section. Operators of master meter systems may comply with this requirement by—

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- (1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and
- (2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.625, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§ 192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

§ 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

Subpart M—Maintenance

§ 192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§ 192.703 General.

- (a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.
- (b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
- (c) Hazardous leaks must be repaired promptly.

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§ 192.705 Transmission lines: Patroling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Class location of line	Maximum interval between patrols	
	At highway and railroad crossings	At all other places
1, 2	7½ months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year.	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year.	4½ months; but at least four times each calendar year.

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.706 Transmission lines: Leakage surveys.

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with § 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

- (a) In Class 3 locations, at intervals not exceeding 7½ months, but at least twice each calendar year; and
- (b) In Class 4 locations, at intervals not exceeding 4½ months, but at least four times each calendar year.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

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§ 192.707 Line markers for mains and transmission lines.

(a) *Buried pipelines.* Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

- (1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

(b) *Exceptions for buried pipelines.* Line markers are not required for the following pipelines:

- (1) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

(2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under § 192.614.

(3) Transmission lines in Class 3 or 4 locations until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) *Pipelines aboveground.* Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Marker warning.* The following must be written legibly on a background of sharply contrasting color on each line marker:

- (1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with ¼ inch (6.4 millimeters) stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

[Amdt. 192-20, 40 FR 13505, Mar. 27, 1975; Amdt. 192-27, 41 FR 39752, Sept. 16, 1976, as amended by Amdt. 192-20A, 41 FR 56808, Dec. 30, 1976; Amdt. 192-44, 48 FR 25208, June 6, 1983; Amdt. 192-73, 60 FR 14650, Mar. 20, 1995; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.709**§ 192.709 Transmission lines: Record keeping.**

Each operator shall maintain the following records for transmission lines for the periods specified:

- (a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.
- (b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.
- (c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

[Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.711 Transmission lines: General requirements for repair procedures.

- (a) Each operator shall take immediate temporary measures to protect the public whenever:

- (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

- (2) It is not feasible to make a permanent repair at the time of discovery.

As soon as feasible, the operator shall make permanent repairs.

- (b) Except as provided in § 192.717(b)(3), no operator may use a welded patch as a means of repair.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27B, 45 FR 3272, Jan. 17, 1980; Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

- (a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

- (1) Removed by cutting out and replacing a cylindrical piece of pipe; or

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- (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

- (b) Operating pressure must be at a safe level during repair operations.

[Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§ 192.715 Transmission lines: Permanent field repair of welds.

Each weld that is unacceptable under § 192.241(c) must be repaired as follows:

- (a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.
- (b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if:

- (1) The weld is not leaking;
- (2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

- (3) Grinding of the defective area can be limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains.

- (c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.717 Transmission lines: Permanent field repair of leaks.

Each permanent field repair of a leak on a transmission line must be made by—

- (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

- (b) Repairing the leak by one of the following methods:

- (1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.

- (2) If the leak is due to a corrosion pit, install a properly designed bolt-on leak clamp.

- (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over

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the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

- (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.

- (5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

[Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§ 192.719 Transmission lines: Testing of repairs.

- (a) *Testing of replacement pipe.* If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is stalled.

- (b) *Testing of repairs made by welding.* Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with § 192.241.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-54, 51 FR 41635, Nov. 18, 1986]

§ 192.721 Distribution systems: Patrolling.

- (a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

- (b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

- (1) In business districts, at intervals not exceeding 4½ months, but at least four times each calendar year; and
- (2) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.723 Distribution systems: Leakage surveys.

- (a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

- (b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

- (1) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

- (2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at intervals not exceeding 5 years. However, for cathodically unprotected distribution lines subject to § 192.465(e) on which electrical surveys for corrosion are impractical, survey intervals may not exceed 3 years.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-70, 58 FR 54528, 54529, Oct. 22, 1993; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.725 Test requirements for reinstating service lines.

- (a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

- (b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.727 Abandonment or deactivation of facilities.

- (a) Each operator shall conduct abandonment or deactivation of pipelines in

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accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

(g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas

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Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.rspa.dot.gov or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@rspa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) Data on pipeline facilities abandoned before October 10, 2000 must be filed by before April 10, 2001. Operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@rspa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party.

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(1) Constructed so that at least 50 percent of its upright side area is permanently open; or

(2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must—

(1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

(2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

[58 FR 48464, Sept. 16, 1993, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.739 Pressure limiting and regulating stations: Inspection and testing.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.741 Pressure limiting and regulating stations: Telemetering or recording gauges.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

§ 192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with § 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.735 Compressor stations: Storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

§ 192.736 Compressor stations: Gas detection.

(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

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(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§ 192.743 Pressure limiting and regulating stations: Testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 15 months, but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-55, 51 FR 41634, Nov. 18, 1986]

§ 192.745 Valve maintenance: Transmission lines.

Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15

months, but at least once each calendar year.

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.747 Valve maintenance: Distribution systems.

Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-46, 63 FR 37504, July 13, 1998]

§ 192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

- (a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.
- (b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.
- (c) Post warning signs, where appropriate.

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Research and Special Programs Administration, DOT**§ 192.805****§ 192.753 Caulked bell and spigot joints.**

(a) Each cast-iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i. (172 kPa) gage or more must be sealed with:

- (1) A mechanical leak clamp, or
- (2) A material or device which:
 - (i) Does not reduce the flexibility of the joint;
 - (ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and
 - (iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§ 192.53 (a) and (b) and 192.143.
- (b) Each cast iron caulked bell and spigot joint that is subject to pressures of less than 25 p.s.i. (172 kPa) gage and is exposed for any reason, must be sealed by a means other than caulking.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-25, 41 FR 23680, June 11, 1976; Amdt. 192-46, 63 FR 37504, July 13, 1998]

§ 192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

- (a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

- (1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
- (2) Impact forces by vehicles;
- (3) Earth movement;
- (4) Apparent future excavations near the pipeline; or
- (5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§ 192.317(a), 192.319, and 192.361(b)-(d).

[Amdt. 192-23, 41 FR 13589, Mar. 31, 1976]

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SOURCE: Amdt. 192-86, 64 FR 46865, Aug. 27, 1999, unless otherwise noted.

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- (d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;
- (e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
- (f) Communicate changes that affect covered tasks to individuals performing those covered tasks; and
- (g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.

§ 192.807 Recordkeeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

- (a) Qualification records shall include:
- (1) Identification of qualified individual(s);
 - (2) Identification of the covered tasks the individual is qualified to perform;
 - (3) Date(s) of current qualification; and
 - (4) Qualification method(s).
- (b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§ 192.809 General.

- (a) Operators must have a written qualification program by April 27, 2001.
- (b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.
- (c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to August 27, 1999.
- (d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

**APPENDIX A TO PART 192—
INCORPORATED BY REFERENCE**

1. List of Organizations and Addresses

- A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

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- B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.
- C. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.
- D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.
- E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19380.
- F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NW., Vienna, VA 22180.
- G. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. 9101, Quincy, MA 02269-9101.

11. Documents Incorporated by Reference (Numbers in Parentheses Indicate Applicable Editions)

- A. American Gas Association (AGA):
- (1) Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 22, 1989).
- B. American Petroleum Institute (API):
- (1) API Specification 5L "Specification for Line Pipe (41st edition, 1995).
 - (2) API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe" (4th edition, 1990).
 - (3) API Specification 6D "Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)" (21st edition, 1994).
 - (4) API Standard 1104 "Welding of Pipelines and Related Facilities" (18th edition, 1994).
- C. American Society for Testing and Materials (ASTM):
- (1) ASTM Designation: A 53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (A53-96).
 - (2) ASTM Designation A 106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-95).
 - (3) ASTM Designation: A 333/A 333M "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (A 333/A 333M-94).
 - (4) ASTM Designation: A 372/A 372M "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A 372/A 372M-95).
 - (5) ASTM Designation: A 381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems" (A 381-93).
 - (6) ASTM Designation: A 671 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A 671-94).
 - (7) ASTM Designation: A 672 "Standard Specification for Electric-Fusion-Welded

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- Steel Pipe for High-Pressure Service at Moderate Temperatures" (A 672-94).
- (8) ASTM Designation A 691 "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (A 691-93).
- (9) ASTM Designation D638 "Standard Test Method for Tensile Properties of Plastics" (D638-96).
- (10) ASTM Designation D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings" (D 2513-97 edition for 192.63(a)(1), otherwise D 2513-96a).
- (11) ASTM Designation D 2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D 2517-94).
- (12) ASTM Designation: F1055 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (F1055-95).
- D. The American Society of Mechanical Engineers (ASME):
- (1) ASME/ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (1989).
 - (2) ASME/ANSI B16.5 "Pipe Flanges and Flanged Fittings" (1988 with October 1988 Errata and ASME/ANSI B16.5a-1992 Addenda).
 - (3) ASME/ANSI B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).
 - (4) ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems" (1995).
 - (5) ASME Boiler and Pressure Vessel Code, Section I "Power Boilers" (1995 edition with 1995 Addenda).
 - (6) ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 "Pressure Vessels" (1995 edition with 1995 Addenda).
 - (7) ASME Boiler and Pressure Vessel Code, Section VIII, Division 2 "Pressure Vessels: Alternative Rules" (1995 edition with 1995 Addenda).
 - (8) ASME Boiler and Pressure Vessel Code, Section IX "Welding and Brazing Qualifications" (1995 edition with 1995 Addenda).
- E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):
1. MSS SP44-96 "Steel Pipe Line Flanges" (includes 1996 errata) (1996).
 2. (Reserved)
- F. National Fire Protection Association (NFPA):
- (1) NFPA 30 "Flammable and Combustible Liquids Code" (1996).
 - (2) ANS/NFPA 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1995).
 - (3) ANS/NFPA 59 "Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1995).

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- (4) ANS/NFPA 70 "National Electrical Code" (1996).
- [58 FR 14521, Mar. 18, 1993, as amended by Amdt. 192-68, 58 FR 45268-45269, Aug. 27, 1993; Amdt. 192-76, 61 FR 26123, May 24, 1996; Amdt. 192-78, 61 FR 28786, June 6, 1996; 61 FR 41020, Aug. 7, 1996; Amdt 192-83, 63 FR 7723, Feb. 17, 1998; Amdt. 192-84, 63 FR 38758, July 20, 1998]
- APPENDIX B TO PART 192—
QUALIFICATION OF PIPE**
- I. Listed Pipe Specifications (Numbers in Parentheses Indicate Applicable Editions)*
- API 5L—Steel pipe (1995).
- ASTM A 53—Steel pipe (1995a).
- ASTM A 106—Steel pipe (1994a).
- ASTM A 333/A 333M—Steel pipe (1994).
- ASTM A 381—Steel pipe (1993).
- ASTM A 671—Steel pipe (1994).
- ASTM A 672—Steel pipe (1994).
- ASTM A 691—Steel pipe (1993).
- ASTM D 2513—Thermoplastic pipe and tubing (1995c).
- ASTM D 2517—Thermosetting plastic pipe and tubing (1994).
- II. Steel pipe of unknown or unlisted specification.*
- A. Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion, with and without opening the longitudinal weld.
- For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53, except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.
- B. Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the file, and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104. If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code. The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L. All test specimens shall be selected at random and the following number of tests must be performed:

NUMBER OF TENSILE TESTS—ALL SIZES

10 lengths or less 11 to 100 lengths	1 set of tests for each length, 1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in § 192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or

rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting appendix B of part 192, see the List of CFR Sections Affected in the Finding Aids section of this volume.

APPENDIX C TO PART 192—QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE

I. *Basic test.* The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. *Additional tests for welders of service line connections to mains.* A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample

as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. *Reference half cells.* A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to -0.85 volt as referred to a saturated copper-copper sulfate half cell:

- (1) Saturated KCl calomel half cell: -0.78 volt.
 (2) Silver-silver chloride half cell used in sea water: -0.80 volt.
 C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.
 [Amdt. 192-4, 36 FR 12305, June 30, 1971]

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

Subpart A—General

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 193.2005 Applicability.
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 193.2011 Reporting.
 193.2013 Incorporation by reference.
 193.2015 [Reserved]
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 193.2019 Mobile and temporary LNG facilities.

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- 193.2051 Scope.
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 193.2057 Thermal radiation protection.
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 DESIGN OF COMPONENTS AND BUILDINGS
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 193.2155 Structural requirements.
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 193.2161 Dikes, general.
 193.2163-193.2165 [Reserved]
 193.2167 Covered systems.
 193.2169-193.2171 [Reserved]
 193.2173 Water removal.
 193.2175-193.2179 [Reserved]
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- LNG STORAGE TANKS
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 193.2306-193.2319 [Reserved]
 193.2321 Nondestructive tests.
 193.2323-193.2329 [Reserved]

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- 193.2401 Scope.
 VAPORIZATION EQUIPMENT
 193.2403-193.2439 [Reserved]
 193.2441 Control center.
 193.2443 [Reserved]
 193.2445 Sources of power.

Subpart F—Operations

- 193.2501 Scope.
 193.2503 Operating procedures.
 193.2505 Coldown.
 193.2507 Monitoring operations.
 193.2509 Emergency procedures.
 193.2511 Personnel safety.
 193.2513 Transfer procedures.
 193.2515 Investigations of failures.
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 193.2603 General.
 193.2605 Maintenance procedures.
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 193.2611 Fire protection.
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 193.2621 Testing transfer hoses.
 193.2623 Inspecting LNG storage tanks.
 193.2625 Corrosion protection.
 193.2627 Atmospheric corrosion control.
 193.2629 External corrosion control: buried or submerged components.
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 193.2633 Interference currents.
 193.2635 Monitoring corrosion control.
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 193.2703 Design and fabrication.
 193.2705 Construction, installation, inspection, and testing.

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of the Federal Power Act (16 U.S.C. 796(8)).

[45 FR 9203, Feb. 11, 1980, as amended by Amdt. 193-1, 45 FR 57418, Aug. 28, 1980; Amdt. 193-10, 61 FR 18517, Apr. 26, 1996]

§ 193.2003 [Reserved]

§ 193.2005 Applicability.

(a) Safety requirements mandating compliance with standard ANSI/NFPA 59A and other changes in this part governing siting, design, construction, equipment, fire protection, operation and maintenance apply to LNG facilities placed in service after March 31, 2000 unless otherwise noted.

(b) If an existing LNG facility (or facility under construction before March 31, 2000) is replaced, relocated or significantly altered after March 31, 2000, the facility must comply with the applicable requirements of this part governing siting, design, installation, and construction, except that:

(1) The siting requirements apply only to LNG storage tanks that are significantly altered by increasing the original storage capacity or relocated, and

(2) To the extent compliance with the design, installation, and construction requirements would make the replaced, relocated, or altered facility incompatible with the other facilities or would otherwise be impracticable, the replaced, relocated, or significantly altered facility may be designed, installed, or constructed in accordance with the original specifications for the facility, or in another manner subject to the approval of the Administrator.

[Amdt. 193-17, 65 FR 10958, Mar. 1, 2000]

§ 193.2007 Definitions.

As used in this part:

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

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Major rivers	Nearest town and state
Smoky Hill River	Abilene, KS.
Susquehanna River	Darlington, MO.
Tennessee River	New Johnsonville, TN.
Wabash River	Harmony, IN.
Wabash River	Terra Haute, IN.
White River	Mt. Carmel, IL.
White River	Batesville, AR.
Wisconsin River	Grand Glaize, AR.
Yukon River	Wisconsin Rapids, WI.
	Fairbanks, AK.

Other Navigable Waters

Arthur Kill Channel, NY
Cook Inlet, AK
Freeport, TX
Los Angeles/Long Beach Harbor, CA
Port Lavaca, TX
San Francisco/San Pablo Bay, CA

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

Subpart A—General

Sec.
195.0 Scope.
195.1 Applicability.
195.2 Definitions.
195.3 Matter incorporated by reference.
195.4 Compatibility necessary for transportation of hazardous liquids or carbon dioxide.
195.5 Conversion to service subject to this part.
195.6 Transportation of hazardous liquid or carbon dioxide in pipelines constructed with other than steel pipe.
195.9 Outer continental shelf pipelines.
195.10 Responsibility of operator for compliance with this part.

Subpart B—Reporting Accidents and Safety-Related Conditions

195.50 Reporting accidents.
195.52 Telephonic notice of certain accidents.
195.54 Accident reports.
195.55 Reporting safety-related conditions.
195.56 Filing safety-related condition reports.
195.57 Filing offshore pipeline condition reports.
195.58 Address for written reports.
195.59 Abandoned underwater facilities report.
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195.62 Supplies of accident report DOT Form 7000-1.
195.63 OMB control number assigned to information collection.

Subpart C—Design Requirements

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195.101 Qualifying metallic components other than pipe.
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195.114 Used pipe.
195.116 Valves.
195.118 Fittings.
195.120 Passage of internal inspection devices.
195.122 Fabricated branch connections.
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195.126 Flange connection.
195.128 Station piping.
195.130 Fabricated assemblies.
195.132 Design and construction of above-ground breakout tanks.
195.134 CPM leak detection.

Subpart D—Construction

195.200 Scope.
195.202 Compliance with specifications or standards.
195.204 Inspection—general.
195.206 Repair, alteration and reconstruction of aboveground breakout tanks that have been in service.
195.208 Welding of supports and braces.
195.210 Pipeline location.
195.212 Bending of pipe.
195.214 Welding: General.
195.216 Welding: Miter joints.
195.222 Welders: Qualification of welders.
195.224 Welding: Weather.
195.226 Welding: Arc burns.
195.228 Welds and welding inspection: Standards of acceptability.
195.230 Welds: Repair or removal of defects.
195.234 Welds: Nondestructive testing.
195.236 External corrosion protection.
195.238 External coating.
195.242 Cathodic protection system.
195.244 Test leads.
195.246 Installation of pipe in a ditch.
195.248 Cover over buried pipeline.
195.250 Clearance between pipe and underground structures.
195.252 Backfilling.
195.254 Above ground components.
195.256 Crossing of railroads and highways.
195.258 Valves: General.
195.260 Valves: Location.
195.262 Pumping equipment.
195.264 Impoundment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks.
195.266 Construction records.

Subpart E—Pressure Testing

195.300 Scope.

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SOURCE: Amdt. 195-22, 46 FR 38360, July 27, 1981, unless otherwise noted.

Subpart A—General

§ 195.0 Scope.

This part prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide.

[Amdt. 195-45, 56 FR 28925, June 12, 1991]

§ 195.1 Applicability.

(a) Except as provided in paragraph (b) of this section, this part applies to pipeline facilities and the transportation of hazardous liquids or carbon dioxide associated with those facilities in or affecting interstate or foreign commerce, including pipeline facilities on the Outer Continental Shelf.
(b) This part does not apply to—
(1) Transportation of a hazardous liquid that is transported in a gaseous state;
(2) Transportation of a hazardous liquid through a pipeline by gravity;
(3) Transportation through any of the following low-stress pipelines:
(i) An onshore pipeline or pipeline segment that—
(A) Does not transport HVL;
(B) Is located in a rural area; and
(C) Is located outside a waterway currently used for commercial navigation;
(ii) A pipeline subject to safety regulations of the U.S. Coast Guard; or
(iii) A pipeline that serves refining, manufacturing, or truck, rail, or vessel terminal facilities, if the pipeline is less than 1 mile long (measured outside facility grounds) and does not cross an offshore area or a waterway currently used for commercial navigation;
(4) Transportation of petroleum in onshore gathering lines in rural areas except gathering lines in the inlets of the Gulf of Mexico subject to § 195.413;
(5) Transportation of hazardous liquid or carbon dioxide in offshore pipelines which are located upstream from the outlet flange of each facility where hydrocarbons or carbon dioxide are produced or where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

Subpart F—Operation and Maintenance

195.400 Scope.
195.401 General requirements.
195.402 Procedural manual for operations, maintenance, and emergencies.
195.403 Training.
195.404 Maps and records.
195.405 Protection against ignitions and safe access/egress involving floating roofs.
195.406 Maximum operating pressure.
195.408 Communications.
195.410 Line markers.
195.412 Inspection of rights-of-way and crossings under navigable waters.
195.413 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.
195.414 Cathodic protection.
195.416 External corrosion control.
195.418 Internal corrosion control.
195.420 Valve maintenance.
195.422 Pipeline repairs.
195.424 Pipe movement.
195.426 Scraper and sphere facilities.
195.428 Overpressure safety devices and overfill protection systems.
195.430 Firefighting equipment.
195.432 Inspection of in-service breakout tanks.
195.434 Signs.
195.436 Security of facilities.
195.438 Smoking or open flames.
195.440 Public education.
195.442 Damage prevention program.
195.444 CPM leak detection.

Subpart G

195.501 Scope.
195.503 Definitions.
195.505 Qualification program.
195.507 Recordkeeping.
195.509 General.
APPENDIX A TO PART 195—DELINEATION BETWEEN FEDERAL AND STATE JURISDICTION—STATEMENT OF AGENCY POLICY AND INTERPRETATION
APPENDIX B TO PART 195—RISK-BASED ALTERNATIVE TO PRESSURE TESTING OLDER HAZARDOUS LIQUID AND CARBON DIOXIDE PIPELINES
AUTHORITY: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

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(6) Transportation of hazardous liquid or carbon dioxide in Outer Continental Shelf pipelines which are located upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

(7) Transportation of a hazardous liquid or carbon dioxide through onshore production (including flow lines), refining, or manufacturing facilities, or storage or in-plant piping systems associated with such facilities;

(8) Transportation of hazardous liquid or carbon dioxide—

(i) By vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation; or

(ii) Through facilities located on the grounds of a materials transportation terminal that are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline, not including any device and associated piping that are necessary to control pressure in the pipeline under § 195.406(b); and

(9) Transportation of carbon dioxide downstream from the following point, as applicable:

(i) The inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream; or

(ii) The connection of the first branch pipeline in the production field that transports carbon dioxide to injection wells or to headers or manifolds from which pipelines branch to injection wells.

(c) Breakout tanks subject to this part must comply with requirements that apply specifically to breakout tanks and, to the extent applicable, with requirements that apply to pipeline systems and pipeline facilities. If a conflict exists between a requirement that applies specifically to breakout tanks and a requirement that applies to pipeline systems or pipeline facilities, the requirement that applies specifically to breakout tanks prevails. Anhydrous ammonia breakout tanks need not comply with §§ 195.132(b), 195.205(b), 195.242 (c) and (d), 195.264 (b)

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and (e), 195.307, 195.428 (c) and (d), and 195.432 (b) and (c).

[Amdt. 195-22, 46 FR 38360, July 27, 1981]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 195.1, see the List of Sections Affected in the Finding Aids section of this volume.

§ 195.2 Definitions.

As used in this part—

Abandoned means permanently removed from service.

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

Barrel means a unit of measurement equal to 42 U.S. standard gallons.

Breakout tank means a tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.

Carbon dioxide means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

Component means any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.

Computation Pipeline Monitoring (CPM) means a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release.

Corrosive product means "corrosive material" as defined by § 173.136 Class 8-Definitions of this chapter.

Exposed pipeline means a pipeline where the top of the pipe is protruding above the seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

Flammable product means "flammable liquid" as defined by § 173.120 Class 3-Definitions of this chapter.

Gathering line means a pipeline 219.1 mm (8 5/8 in) or less nominal outside diameter that transports petroleum from a production facility.

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and

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its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to navigation means, for the purpose of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

Hazardous liquid means petroleum, petroleum products, or anhydrous ammonia.

Highly volatile liquid or *HVL* means a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa (40 psia) at 37.8° C (100° F).

In-plant piping system means piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transportation, not including any device and associated piping that are necessary to control pressure in the pipeline under § 195.406(b).

Interstate pipeline means a pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.

Intrastate pipeline means a pipeline or that part of a pipeline to which this part applies that is not an interstate pipeline.

Line section means a continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and a block valve, or between adjacent block valves.

Low-stress pipeline means a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

Nominal wall thickness means the wall thickness listed in the pipe specifications.

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is

in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator means a person who owns or operates pipeline facilities.

Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

Petroleum means crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

Petroleum product means flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.

Pipe or line pipe means a tube, usually cylindrical, through which a hazardous liquid or carbon dioxide flows from one point to another.

Pipeline or pipeline system means all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

Pipeline facility means new and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide.

Production facility means piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or

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carbon dioxide from the ground or from facilities where CO₂ is produced, and preparing it for transportation by pipeline. This includes piping between treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)

Rural area means outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development.

Specified minimum yield strength means the minimum yield strength, expressed in p.s.i. (kPa) gage, prescribed by the specification under which the material is purchased from the manufacturer.

Stress level means the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

Surge pressure means pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

Toxic product means "poisonous material" as defined by §173.132 Class 6, Division 6.1-Definitions of this chapter.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-33, 50 FR 15898, Apr. 23, 1985; 50 FR 38660, Sept. 24, 1985; Amdt. 195-36, 51 FR 15007, Apr. 22, 1986; Amdt. 195-45, 56 FR 26925, June 12, 1991; Amdt. 195-50, 59 FR 17281, Apr. 12, 1994; Amdt. 195-52, 59 FR 33395, 33396, June 28, 1994; Amdt. 195-53, 59 FR 35471, July 12, 1994; Amdt. 195-58, 62 FR 61695, Nov. 19, 1997; Amdt. 195-62, 63 FR 37506, July 13, 1998; Amdt. 195-63, 63 FR 54444, Sept. 8, 2000]

EFFECTIVE DATE NOTE: At 65 FR 54444, Sept. 8, 2000, § 195.2 was amended by adding the definition of "Abandoned", effective Oct. 10, 2000.

§ 195.3 Matter incorporated by reference.

(a) Any document or portion thereof incorporated by reference in this part is included in this part as though it were printed in full. When only a portion of a document is referenced, then this part incorporates only that reference.

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erenced portion of the document and the remainder is not incorporated. Applicable editions are listed in paragraph (c) of this section in parentheses following the title of the referenced material. Earlier editions listed in previous editions of this section may be used for components manufactured, designed, or installed in accordance with those earlier editions at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR for a listing of the earlier editions.

(b) All incorporated materials are available for inspection in the Research and Special Programs Administration, 400 Seventh Street, SW., Washington, DC, and at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, materials incorporated by reference are available as follows:

(1) American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

(2) American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.

(3) The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.

(4) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NE., Vienna, VA 22180.

(5) American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.

(6) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

(7) National Fire Protection Association (NFPA), 11 Tracy Drive, Avon, MA 02322.

(c) The full titles of publications incorporated by reference wholly or partially in this part are as follows. Numbers in parentheses indicate applicable editions:

(1) American Gas Association (AGA): AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining

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Strength of Corroded Pipe" (December 1989). The RSTRENG program may be used for calculating remaining strength.

(2) American Petroleum Institute (API):

(i) API 510 "Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration" (8th edition, June 1997).

(ii) API 1130 "Computational Pipeline Monitoring" (1st Edition, 1995).

(iii) API Publication 2026 "Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service" (2nd edition, April 1998).

(iv) API Recommended Practice 651 "Cathodic Protection of Aboveground Petroleum Storage Tanks" (2nd edition, December 1997).

(v) API Recommended Practice 652 "Lining of Aboveground Petroleum Storage Tank Bottoms" (2nd edition, December 1997).

(vi) API Recommended Practice 2003 "Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents" (6th edition, December 1998).

(vii) API Recommended Practice 2350 "Overfill Protection for Storage Tanks in Petroleum Facilities" (2nd edition, January 1996).

(viii) API Specification 5L "Specification for Line Pipe" (41st edition, 1995).

(ix) API Specification 6D "Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)" (21st edition, 1994).

(x) API Specification 12F "Specification for Shop Welded Tanks for Storage of Production Liquids" (11th edition, November 1994).

(xi) API Standard 1104 "Welding Pipelines and Related Facilities" (18th edition, 1994).

(xii) API Standard 620 "Design and Construction of Large, Welded, Low-Pressure Storage Tanks" (9th edition, February 1996, including Addenda 1 and 2).

(xiii) API Standard 650 "Welded Steel Tanks for Oil Storage" (9th edition, July 1993 (including Addenda 1 through 4).

(xiv) API Standard 653 "Tank Inspection, Repair, Alteration, and Reconstruction" (2nd edition, December 1995, including Addenda 1 & 2).

(xv) API Standard 2000 "Venting Atmospheric and Low-Pressure Storage Tanks" (4th edition, September 1992).

(xvi) API Standard 2510 "Design and Construction of LPG Installations" (7th edition, May 1995).

(3) American Society of Mechanical Engineers (ASME):

(i) ASME/ANSI B16.9 "Factory-Made Wrought Steel Buttwelding Fittings" (1993).

(ii) ASME/ANSI B31.4 "Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols" (1992 edition with ASME B31.4a-1994 Addenda).

(iii) ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems" (1995).

(iv) ASME/ANSI B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).

(v) ASME Boiler and Pressure Vessel Code, Section VIII "Pressure Vessels," Divisions 1 and 2 (1995 edition with 1995 Addenda).

(vi) ASME Boiler and Pressure Vessel Code, Section IX "Welding and Brazing Qualifications" (1995 edition with 1995 Addenda).

(4) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):

(i) MSS SP-75 "Specification for High Test Wrought Butt Welding Fittings" (1993).

(ii) [Reserved]

(5) American Society for Testing and Materials (ASTM):

(i) ASTM Designation A 53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless" (A 53-96).

(ii) ASTM Designation: A 106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A 106-95).

(iii) ASTM Designation: A 333/A 333M "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (A 333/A 333M-94).

(iv) ASTM Designation: A 381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems" (A 381-93).

(v) ASTM Designation: A 671 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Use With High-Pressure Transmission Systems" (A 671-93).

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Welded Steel Pipe for Atmospheric and Lower Temperatures" (A 671-94).

(vi) ASTM Designation: A 672 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (A 672-94).

(vii) ASTM Designation: A 691 "Standard Specification for Carbon and Alloy Steel Pipe Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (A 691-93).

(6) National Fire Protection Association (NFPA):

(i) ANSI/NFPA 30 "Flammable and Combustible Liquids Code," (1996).

(ii) [Reserved]

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-32, 49 FR 36860, Sept. 20, 1984; 58 FR 14523, Mar. 18, 1993; Amdt. 195-52, 59 FR 33396, June 28, 1994; Amdt. 195-56, 61 FR 26123, May 24, 1996; 61 FR 36826, July 15, 1996; Amdt. 195-61, 63 FR 7723, Feb. 17, 1998; Amdt. 195-62, 63 FR 38376, July 6, 1998; Amdt. 195-66, 64 FR 15934, Apr. 2, 1999; 65 FR 4770, Feb. 1, 2000]

§ 195.4 Compatibility necessary for transportation of hazardous liquids or carbon dioxide.

No person may transport any hazardous liquid or carbon dioxide unless the hazardous liquid or carbon dioxide is chemically compatible with both the pipeline, including all components, and any other commodity that it may come into contact with while in the pipeline.

[Amdt. 195-45, 56 FR 26925, June 12, 1991]

§ 195.5 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to accomplish the following:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in satisfactory condition for safe operation. If one or more of the variables necessary to verify the design pressure under § 195.106 or to perform the testing under paragraph (a)(4) of this section is unknown, the design pressure may be

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verified and the maximum operating pressure determined by—

(i) Testing the pipeline in accordance with ASME B31.8, Appendix N, to produce a stress equal to the yield strength; and

(ii) Applying, to not more than 80 percent of the first pressure that produces a yielding, the design factor F in § 195.106(a) and the appropriate factors in § 195.106(e).

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with subpart E of this part to substantiate the maximum operating pressure permitted by § 195.406.

(b) A pipeline which qualifies for use under this section need not comply with the corrosion control requirements of this part until 12 months after it is placed in service, notwithstanding any earlier deadlines for compliance. In addition to the requirements of subpart F of this part, the corrosion control requirements of subpart D apply to each pipeline which substantially meets those requirements before it is placed in service or which is a segment that is replaced, relocated, or substantially altered.

(c) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-52, 59 FR 33396, June 28, 1994]

§ 195.8 Transportation of hazardous liquid or carbon dioxide in pipelines constructed with other than steel pipe.

No person may transport any hazardous liquid or carbon dioxide through a pipe that is constructed after October 1, 1970, for hazardous liquids or after

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ance of any action required by this part. However, the operator is not thereby relieved from the responsibility for compliance with any requirement of this part.

Subpart B—Reporting Accidents and Safety-Related Conditions**§ 195.50 Reporting accidents.**

An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following:

(a) Explosion or fire not intentionally set by the operator.
(b) Loss of 50 or more barrels (8 or more cubic meters) of hazardous liquid or carbon dioxide.
(c) Escape to the atmosphere of more than 5 barrels (0.8 cubic meters) a day of highly volatile liquids.
(d) Death of any person.
(e) Bodily harm to any person resulting in one or more of the following:

(1) Loss of consciousness.
(2) Necessity to carry the person from the scene.
(3) Necessity for medical treatment.
(4) Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.

(f) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding \$50,000.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-39, 53 FR 24950, July 1, 1988; Amdt. 195-45, 56 FR 26925, June 12, 1991; Amdt. 195-52, 59 FR 33396, June 28, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.52 Telephonic notice of certain accidents.

(a) At the earliest practicable moment following discovery of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in § 195.50, the operator of the system shall give notice, in accordance with paragraph (b) of this section, of any failure that:

(1) Caused a death or a personal injury requiring hospitalization.

July 12, 1991 for carbon dioxide of material other than steel unless the person has notified the Administrator in writing at least 90 days before the transportation is to begin. The notice must state whether carbon dioxide or a hazardous liquid is to be transported and the chemical name, common name, properties and characteristics of the hazardous liquid to be transported and the material used in construction of the pipeline. If the Administrator determines that the transportation of the hazardous liquid or carbon dioxide in the manner proposed would be unduly hazardous, he will, within 90 days after receipt of the notice, order the person that gave the notice, in writing, not to transport the hazardous liquid or carbon dioxide in the proposed manner until further notice.

[Amdt. 195-45, 56 FR 26925, June 12, 1991, as amended by Amdt. 195-50, 59 FR 17281, Apr. 12, 1994]

§ 195.9 Outer continental shelf pipelines.

Operators of transportation pipelines on the Outer Continental Shelf must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic maintained near the transfer point. If a transfer point is located on a subsea, the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to RSPA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Amdt. 195-59, 62 FR 61695, Nov. 19, 1997]

§ 195.10 Responsibility of operator for compliance with this part.

An operator may make arrangements with another person for the perform-

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(2) Resulted in either a fire or explosion not intentionally set by the operator;

(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding \$50,000;

(4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or

(5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

(b) Reports made under paragraph (a) of this section are made by telephone to 800-424-9802 (in Washington, DC 287-2675) and must include the following information:

(1) Name and address of the operator.

(2) Name and telephone number of the reporter.

(3) The location of the failure.

(4) The time of the failure.

(5) The fatalities and personal injuries, if any.

(6) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-23, 47 FR 32720, July 28, 1982; Amdt. 195-44, 54 FR 40878, Oct. 4, 1989; Amdt. 195-45, 56 FR 28925, June 12, 1991; Amdt. 195-52, 59 FR 33396, June 28, 1994]

§ 195.54 Accident reports.

(a) Each operator that experiences an accident that is required to be reported under § 195.50 shall as soon as practicable, but not later than 30 days after discovery of the accident, prepare and file an accident report on DOT Form 7000-1, or a facsimile.

(b) Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form 7000-1, it shall file a supplemental report within 30 days.

[Amdt. 195-39, 53 FR 24950, July 1, 1988]

49 CFR Ch. I (10-1-00 Edition)**§ 195.55 Reporting safety-related conditions.**

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with § 195.56 the existence of any of the following safety-related conditions involving pipelines in service:

(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) Unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, or flood, that impairs its serviceability.

(3) Any material defect or physical damage that impairs the serviceability of a pipeline.

(4) Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure.

(5) A leak in a pipeline that constitutes an emergency.

(6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly) by remedial action of the operator, for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

(b) A report is not required for any safety-related condition that—

(1) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water;

(2) Is an accident that is required to be reported under § 195.50 or results in such an accident before the deadline for filing the safety-related condition report; or

(3) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for

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filled the safety-related condition report, except that reports are required for all conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

[Amdt. 195-39, 53 FR 24950, July 1, 1988; 53 FR 29800, Aug. 8, 1988, as amended by Amdt. 195-42, 54 FR 32344, Aug. 7, 1989; Amdt. 195-44, 54 FR 40878, Oct. 4, 1989; Amdt. 195-50, 56 FR 17281, Apr. 12, 1994; Amdt. 195-61, 63 FR 7723, Feb. 17, 1998]

§ 195.56 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 195.55(a) must be filed (received by the Administrator) in writing within 5 working days (not including Saturdays, Sundays, or Federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. To file a report by facsimile (fax), dial (202) 366-7128.

(b) The report must be headed "Safety-Related Condition Report" and provide the following information:

(1) Name and principal address of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Total number of miles (kilometers) of pipeline inspected.

(5) Length and date of installation of each exposed pipeline segment, and location; including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.

(6) Length and date of installation of each pipeline segment, if different from a pipeline segment identified under paragraph (a)(5) of this section, that is a hazard to navigation, and the location; including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.

(7) The report shall be mailed to the Information Officer, Research and Special Programs Administration, Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590.

[Amdt. 195-47, 56 FR 63771, Dec. 5, 1991, as amended by Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.58 Address for written reports.

Each written report required by this subpart must be made to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 2335, 400 Seventh Street SW., Washington DC 20590. However, accident reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant

to the safety-related condition report, except that reports are required for all conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

[Amdt. 195-39, 53 FR 24950, July 1, 1988; 53 FR 29800, Aug. 8, 1988, as amended by Amdt. 195-42, 54 FR 32344, Aug. 7, 1989; Amdt. 195-44, 54 FR 40878, Oct. 4, 1989; Amdt. 195-50, 56 FR 17281, Apr. 12, 1994; Amdt. 195-61, 63 FR 7723, Feb. 17, 1998]

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to a certification under the pipeline safety laws (49 U.S.C. 60101 et seq.) may be submitted in duplicate to that State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy within 10 days of receipt to the Information Resources Manager. Safety-related condition reports required by § 195.55 for intrastate pipelines must be submitted concurrently to the State agency, and if that agency acts as an agent of the Secretary with respect to interstate pipelines, safety-related condition reports for these pipelines must be submitted concurrently to that agency.

[Amdt. 195-55, 61 FR 18518, Apr. 26, 1996]

§ 195.59 Abandoned underwater facilities report.

For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(a) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.rspa.dot.gov or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Spe-

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cial Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@rspa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(b) Data on pipeline facilities abandoned before October 10, 2000 must be filed by before April 10, 2001. Operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@rspa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

[Amdt. 195-59, 65 FR 54444, Sept. 8, 2000]

EFFECTIVE DATE NOTE: At 65 FR 54444, Sept. 8, 2000, § 195.59 was added, effective Oct. 10, 2000.

§ 195.60 Operator assistance in investigation.

If the Department of Transportation investigates an accident, the operator involved shall make available to the representative of the Department all records and information that in any way pertain to the accident, and shall afford all reasonable assistance in the investigation of the accident.

§ 195.62 Supplies of accident report DOT Form 7000-1.

Each operator shall maintain an adequate supply of forms that are a facsimile of DOT Form 7000-1 to enable it to promptly report accidents. The Department will, upon request, furnish specimen copies of the form. Requests should be addressed to the Information Resources Manager, Office of Pipeline

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Safety, Department of Transportation, Washington, DC 20590.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended at 47 FR 32720, July 29, 1982]

§ 195.63 OMB control number assigned to information collection.

The control number assigned by the Office of Management and Budget to the hazardous liquid pipeline information collection requirements of this part pursuant to the Paperwork Reduction Act of 1980 is 2137-0047.

[Amdt. 195-34, 50 FR 34474, Aug. 26, 1985]

Subpart C—Design Requirements**§ 195.100 Scope.**

This subpart prescribes minimum design requirements for new pipeline systems constructed with steel pipe and for relocating, replacing, or otherwise changing existing systems constructed with steel pipe. However, it does not apply to the movement of line pipe covered by § 195.424.

§ 195.101 Qualifying metallic components other than pipe.

Notwithstanding any requirement of the subpart which incorporates by reference an edition of a document listed in § 195.3, a metallic component other than pipe manufactured in accordance with any other edition of that document is qualified for use if—

- It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and
- The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in § 195.3:
 - Pressure testing;
 - Materials; and
 - Pressure and temperature ratings.

[Amdt. 195-28, 48 FR 30639, July 5, 1983]

§ 195.102 Design temperature.

(a) Material for components of the system must be chosen for the temperature environment in which the components will be used so that the

pipeline will maintain its structural integrity.

(b) Components of carbon dioxide pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures.

[Amdt. 195-45, 56 FR 26925, June 12, 1991]

§ 195.104 Variations in pressure.

If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed.

§ 195.106 Internal design pressure.

(a) Internal design pressure for the pipe in a pipeline is determined in accordance with the following formula:

$$P=(2St/D) \times E \times F$$

P =Internal design pressure in p.s.i. (kPa) gage.

S =Yield strength in pounds per square inch (kPa) determined in accordance with paragraph (b) of this section.

t =Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with paragraph (c) of this section.

D =Nominal outside diameter of the pipe in inches (millimeters).

E =Seam joint factor determined in accordance with paragraph (e) of this section.

F =A design factor of 0.72, except that a design factor of 0.60 is used for a pipe, including risers, on a platform located offshore or on a platform in inland navigable waters, and 0.54 is used for pipe that has been subjected to cold expansion to meet the specified minimum yield strength and is subsequently heated, other than by welding or stress relieving as a part of welding, to a temperature higher than 900° F (482° C) for any period of time or over 600° F (316° C) for more than 1 hour.

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ameter, nor more than 1.11 times the smallest measurement taken on pipe that is 20 inches (508 mm) or more in nominal outside diameter.

(d) The minimum wall thickness of the pipe may not be less than 87.5 percent of the value used for nominal wall thickness in determining the internal design pressure under paragraph (a) of this section. In addition, the anticipated external loads and external pressures that are concurrent with internal pressure must be considered in accordance with §§ 195.108 and 195.110 and, after determining the internal design pressure, the nominal wall thickness must be increased as necessary to compensate for these concurrent loads and pressures.

(e) The seam joint factor used in paragraph (a) of this section is determined in accordance with the following table:

Specification	Pipe class	Seam joint factor
ASTM A53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace lap welded	0.80
ASTM A106	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.80
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.80
ASTM A331	Double submerged arc welded	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.80
ASTM A671	Electric resistance welded	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.80
ASTM A691	Electric resistance welded	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.80
API 5L	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.80

The seam joint factor for pipe which is not covered by this paragraph must be approved by the Administrator.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-30, 49 FR 7569, Mar. 1, 1984; Amdt. 195-37, 51 FR 15335, Apr. 23, 1986; Amdt. 195-40, 54 FR 5628, Feb. 6, 1989; 58 FR 14524, Mar. 18, 1993; Amdt. 195-50, 59 FR 17281, Apr. 12, 1994; Amdt. 195-52, 59 FR 33396, 33397, June 28, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.108 External pressure.

Any external pressure that will be exerted on the pipe must be provided for in designing a pipeline system.

(b) The yield strength to be used in determining the internal design pressure under paragraph (a) of this section is the specified minimum yield strength. If the specified minimum yield strength is not known, the yield strength to be used in the design formula is one of the following:

(1)(i) The yield strength determined by performing all of the tensile tests of API Specification 5L on randomly selected specimens with the following number of tests:

Pipe size	No. of tests
Less than 6% in (168 mm) nominal outside diameter.	One test for each 200 lengths.
6% in through 12% in (168 mm through 324 mm) nominal outside diameter.	One test for each 100 lengths.
Larger than 12% in (324 mm) nominal outside diameter.	One test for each 50 lengths.

(ii) If the average yield-tensile ratio exceeds 0.85, the yield strength shall be taken as 24,000 p.s.i. (165,474 kPa). If the average yield-tensile ratio is 0.85 or less, the yield strength of the pipe is taken as the lower of the following:

(A) Eighty percent of the average yield strength determined by the tensile tests.

(B) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b) of this section, the yield strength shall be taken as 24,000 p.s.i. (165,474 kPa).

(c) If the nominal wall thickness to be used in determining internal design pressure under paragraph (a) of this section is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end. However, if the pipe is of uniform grade, size, and thickness, only 10 individual lengths or 5 percent of all lengths, whichever is greater, need be measured. The thickness of the lengths that are not measured must be verified by applying a gage set to the minimum thickness found by the measurement. The nominal wall thickness to be used is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness may not be more than 1.14 times the smallest measurement taken on pipe that is less than 20 inches (508 mm) nominal outside di-

§ 195.110 External loads.

(a) Anticipated external loads (e.g., earthquakes, vibration, thermal expansion, and contraction) must be provided for in designing a pipeline system. In providing for expansion and flexibility, section 419 of ASME/ANSI B31.4 must be followed.

(b) The pipe and other components must be supported in such a way that the support does not cause excess localized stresses. In designing attachments to pipe, the added stress to the wall of the pipe must be computed and compensated for.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended at 58 FR 14524, Mar. 18, 1993]

§ 195.111 Fracture propagation.

A carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation.

[Amdt. 195-45, 56 FR 28226, June 12, 1991]

§ 195.112 New pipe.

Any new pipe installed in a pipeline system must comply with the following:

(a) The pipe must be made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system.

(b) The pipe must be made in accordance with a written pipe specification that sets forth the chemical requirements for the pipe steel and mechanical tests for the pipe to provide pipe suitable for the use intended.

(c) Each length of pipe with a nominal outside diameter of 4 1/2 in (114.3 mm) or more must be marked on the pipe or pipe coating with the specification to which it was made, the specified minimum yield strength or grade, and the pipe size. The marking must be applied in a manner that does not damage the pipe or pipe coating and must remain visible until the pipe is installed.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-52, 59 FR 33396, June 28, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.114 Used pipe.

Any used pipe installed in a pipeline system must comply with § 195.112 (a) and (b) and the following:

(a) The pipe must be of a known specification and the seam joint factor must be determined in accordance with § 195.108(e). If the specified minimum yield strength or the wall thickness is not known, it is determined in accordance with § 195.106 (b) or (c) as appropriate.

(b) There may not be any:

- (1) Buckles;
- (2) Cracks, grooves, gouges, dents, or other surface defects that exceed the maximum depth of such a defect permitted by the specification to which the pipe was manufactured; or
- (3) Corroded areas where the remaining wall thickness is less than the minimum thickness required by the tolerances in the specification to which the pipe was manufactured.

However, pipe that does not meet the requirements of paragraph (b)(3) of this section may be used if the operating pressure is reduced to be commensurate with the remaining wall thickness.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982]

§ 195.116 Valves.

Each valve installed in a pipeline system must comply with the following:

(a) The valve must be of a sound engineering design.

(b) Materials subject to the internal pressure of the pipeline system, including welded and flanged ends, must be compatible with the pipe or fittings to which the valve is attached.

(c) Each part of the valve that will be in contact with the carbon dioxide or hazardous liquid stream must be made of materials that are compatible with carbon dioxide or each hazardous liquid that it is anticipated will flow through the pipeline system.

(d) Each valve must be both hydrostatically shell tested and hydrostatically seat tested without leakage to at least the requirements set forth in section 5 of API Standard 6D.

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(e) Each valve other than a check valve must be equipped with a means for clearly indicating the position of the valve (open, closed, etc.).

(f) Each valve must be marked on the body or the nameplate, with at least the following:

- (1) Manufacturer's name or trade-mark.
- (2) Class designation or the maximum working pressure to which the valve may be subjected.
- (3) Body material designation (the end connection material, if more than one type is used).
- (4) Nominal valve size.

[Amdt. 195-22, 46 FR 38360, July 27, 1981 as amended by Amdt. 195-45, 56 FR 26926, June 12, 1991]

§ 195.118 Fittings.

(a) Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75.

(b) There may not be any buckles, dents, cracks, gouges, or other defects in the fitting that might reduce the strength of the fitting.

(c) The fitting must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system to which it is attached.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended at 58 FR 14524, Mar. 18, 1993]

§ 195.120 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to:

- (1) Manifolds;
- (2) Station piping such as at pump stations, meter stations, or pressure reducing stations;
- (3) Piping associated with tank farms and other storage facilities;
- (4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Offshore pipelines, other than main lines 10 inches (254 millimeters) or greater in nominal diameter, that transport liquids to onshore facilities; and

(7) Other piping that the Administrator under § 190.9 of this chapter, finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints, and other unforeseen construction problems need not construct a new or replacement segment of a pipeline to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under § 190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Amdt. 195-50, 59 FR 17281, Apr. 12, 1994, as amended by Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.122 Fabricated branch connections.

Each pipeline system must be designed so that the addition of any fabricated branch connections will not reduce the strength of the pipeline system.

§ 195.124 Closures.

Each closure to be installed in a pipeline system must comply with the ASME Boiler and Pressure Vessel Code, section VIII, Pressure Vessels, Division 1, and must have pressure and temperature ratings at least equal to those of the pipe to which the closure is attached.

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greater than 15 psig (103.4 kPa)) with a nominal capacity of 2000 gallons (7571 liters) or more of liquefied petroleum gas (LPG) must be designed and constructed in accordance with API Standard 2510.

[Amdt. 195-66, 64 FR 15935, Apr. 2, 1999]

§ 195.134 CPM leak detection.

This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such systems, each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system must comply with section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system.

[Amdt. 195-62, 63 FR 36376, July 6, 1998]

Subpart D—Construction

§ 195.200 Scope.

This subpart prescribes minimum requirements for constructing new pipeline systems with steel pipe, and for relocating, replacing, or otherwise changing existing pipeline systems that are constructed with steel pipe. However, this subpart does not apply to the movement of pipe covered by § 195.424.

§ 195.202 Compliance with specifications or standards.

Each pipeline system must be constructed in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part.

§ 195.204 Inspection—general.

Inspection must be provided to ensure the installation of pipe or pipeline systems in accordance with the requirements of this subpart. No person may be used to perform inspections unless that person has been trained and is qualified in the phase of construction to be inspected.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-52, 59 FR 33397, June 28, 1994]

§ 195.126 Flange connection.

Each component of a flange connection must be compatible with each other component and the connection as a unit must be suitable for the service in which it is to be used.

§ 195.128 Station piping.

Any pipe to be installed in a station that is subject to system pressure must meet the applicable requirements of this subpart.

§ 195.130 Fabricated assemblies.

Each fabricated assembly to be installed in a pipeline system must meet the applicable requirements of this subpart.

§ 195.132 Design and construction of aboveground breakout tanks.

(a) Each aboveground breakout tank must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.

(b) For aboveground breakout tanks first placed in service after October 2, 2000, compliance with paragraph (a) of this section requires one of the following:

(1) Shop-fabricated, vertical, cylindrical, closed top, welded steel tanks with nominal capacities of 90 to 750 barrels (14.3 to 119.2 m³) and with internal vapor space pressures that are approximately atmospheric must be designed and constructed in accordance with API Specification 12F.

(2) Welded, low-pressure (i.e., internal vapor space pressure not greater than 15 psig (103.4 kPa)), carbon steel tanks that have wall shapes that can be generated by a single vertical axis of revolution must be designed and constructed in accordance with API Standard 620.

(3) Vertical, cylindrical, welded steel tanks with internal pressures at the tank top approximating atmospheric pressures (i.e., internal vapor space pressures not greater than 2.5 psig (17.2 kPa), or not greater than the pressure developed by the weight of the tank roof) must be designed and constructed in accordance with API Standard 650.

(4) High pressure steel tanks (i.e., internal gas or vapor space pressures

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§ 195.205 Repair, alteration and reconstruction of aboveground breakout tanks that have been in service.

- (a) Aboveground breakout tanks that have been repaired, altered, or reconstructed and returned to service must be capable of withstanding the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.
- (b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the tanks specified:

- (1) For tanks designed for approximately atmospheric pressure constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C, repair, alteration, and reconstruction must be in accordance with API Standard 653.
- (2) For tanks built to API Specification 12F or API Standard 620, the repair, alteration, and reconstruction must be in accordance with the design, welding, examination, and material requirements of those respective standards.
- (3) For high pressure tanks built to API Standard 2510, repairs, alterations, and reconstruction must be in accordance with API 510.

[Amdt. 195-66, 64 FR 15935, Apr. 2, 1999]

§ 195.206 Material inspection.

No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability.

§ 195.208 Welding of supports and braces.

Supports or braces may not be welded directly to pipe that will be operated at a pressure of more than 100 p.s.i. (689 kPa) gage.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.210 Pipeline location.

- (a) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, in-

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dustrial buildings, and places of public assembly.

- (b) No pipeline may be located within 50 feet (15 meters) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches (305 millimeters) of cover in addition to that prescribed in § 195.248.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.212 Bending of pipe.

- (a) Pipe must not have a wrinkle bend.
- (b) Each field bend must comply with the following:

- (1) A bend must not impair the serviceability of the pipe.
- (2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.
- (3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless—
 - (i) The bend is made with an internal bending mandrel; or
 - (ii) The pipe is 12% in (324 mm) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70.
- (c) Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-52, 59 FR 33396, June 28, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.214 Welding: General.

- (a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.
- (b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record

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weld, the acceptability of the weld may be determined under that appendix.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-52, 59 FR 33397, June 28, 1994]

§ 195.230 Welds: Repair or removal of defects.

- (a) Each weld that is unacceptable under § 195.228 must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

- (b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

- (c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under § 195.214. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 195-22, 48 FR 48674, Oct. 20, 1983]

§ 195.234 Welds: Nondestructive testing.

- (a) A weld may be nondestructively tested by any process that will clearly indicate any defects that may affect the integrity of the weld.

- (b) Any nondestructive testing of welds must be performed—

- (1) In accordance with a written set of procedures for nondestructive testing; and

- (2) With personnel that have been trained in the established procedures and in the use of the equipment employed in the testing.

- (c) Procedures for the proper interpretation of each weld inspection must be established to ensure the acceptability of the weld under § 195.228.

- (d) During construction, at least 10 percent of the girth welds made by each welder during each welding day

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must be nondestructively tested over the entire circumference of the weld.

(e) All girth welds installed each day in the following locations must be non-destructively tested over their entire circumference, except that when non-destructive testing is impracticable for a girth weld, it need not be tested if the number of girth welds for which testing is impracticable does not exceed 10 percent of the girth welds installed that day:

(1) At any onshore location where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water, and any offshore area;

(2) Within railroad or public road rights-of-way;

(3) At overhead road crossings and within tunnels;

(4) Within the limits of any incorporated subdivision of a State government; and

(5) Within populated areas, including, but not limited to, residential subdivisions, shopping centers, schools, designated commercial areas, industrial facilities, public institutions, and places of public assembly.

(f) When installing used pipe, 100 percent of the old girth welds must be nondestructively tested.

(g) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent of the girth welds must be nondestructively tested.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-35, 50 FR 37192, Sept. 21, 1985; Amdt. 195-52, 59 FR 33397, June 28, 1994]

§ 195.236 External corrosion protection.

Each component in the pipeline system must be provided with protection against external corrosion.

§ 195.238 External coating.

(a) No pipeline system component may be buried or submerged unless that component has an external protective coating that—

(1) Is designed to mitigate corrosion of the buried or submerged component;

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(2) Has sufficient adhesion to the metal surface to prevent underfilm migration of moisture;

(3) Is sufficiently ductile to resist cracking;

(4) Has enough strength to resist damage due to handling and soil stress; and

(5) Supports any supplemental cathodic protection.

In addition, if an insulating-type coating is used it must have low moisture absorption and provide high electrical resistance.

(b) All pipe coating must be inspected just prior to lowering the pipe into the ditch or submerging the pipe, and any damage discovered must be repaired.

§ 195.242 Cathodic protection system.

(a) A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure.

A test procedure must be developed to determine whether adequate cathodic protection has been achieved.

(b) A cathodic protection system must be installed not later than 1 year after completing the construction.

(c) For the bottoms of aboveground breakout tanks with greater than 500 barrels (79.5 m³) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), the installation of a cathodic protection system under paragraph (a) of this section after October 2, 2000, must be in accordance with API Recommended Practice 651, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of a particular breakout tank.

(d) For the internal bottom of aboveground breakout tanks built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), the installation of a tank bottom lining after October 2, 2000, must be in accordance with API Recommended Practice 652, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with

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all or certain provisions of API Recommended Practice 652 is not necessary for the safety of a particular breakout tank.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-66, 64 FR 15935, Apr. 2, 1999]

§ 195.244 Test leads.

(a) Except for offshore pipelines, electrical test leads used for corrosion control or electrolysis testing must be installed at intervals frequent enough to obtain electrical measurements indicating the adequacy of the cathodic protection.

(b) Test leads must be installed as follows:

(1) Enough looping or slack must be provided to prevent test leads from being unduly stressed or broken during backfilling.

(2) Each lead must be attached to the pipe so as to prevent stress concentration on the pipe.

(3) Each lead installed in a conduit must be suitably insulated from the conduit.

§ 195.246 Installation of pipe in a ditch.

(a) All pipe installed in a ditch must be installed in a manner that mini-

mizes the introduction of secondary stresses and the possibility of damage to the pipe.

(b) Except for pipe in the Gulf of Mexico and its inlets, all offshore pipe in water at least 3.7 m (12 ft) deep but not more than 61 m (200 ft) deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-52, 59 FR 33397, June 28, 1994; 59 FR 36256, July 15, 1994]

§ 195.248 Cover over buried pipeline.

(a) Unless specifically exempted in this subpart, all pipe must be buried so that it is below the level of cultivation. Except as provided in paragraph (b) of this section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, river bottom, or sea bottom, as applicable, complies with the following table:

Location	Cover inches (millimeters)	
	For normal excavation	For rock excavation
Industrial, commercial, and residential areas	36 (914)	30 (762)
Crossings of inland bodies of water with a width of at least 100 ft (30 m) from high water mark to high water mark	48 (1219)	18 (457)
Drainage ditches at public roads and railroads	36 (914)	36 (914)
Deepwater port safety zone	48 (1219)	24 (610)
Gulf of Mexico and its inlets and other offshore areas under water less than 12 ft (3.7 m) deep as measured from the mean low tide	36 (914)	18 (457)
Any other area	30 (762)	18 (457)

¹ Rock excavation is any excavation that requires blasting or removal by equivalent means.

(b) Except for the Gulf of Mexico and its inlets, less cover than the minimum required by paragraph (a) of this section and § 195.210 may be used if—

(1) It is impracticable to comply with the minimum cover requirements; and

(2) Additional protection is provided that is equivalent to the minimum required cover.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982 as amended by Amdt. 195-52, 59 FR 33397, June 28, 1994; 59 FR 36256, July 15, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

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§ 195.250 Clearance between pipe and underground structures.

Any pipe installed underground must have at least 12 inches (305 millimeters) of clearance between the outside of the pipe and the extremity of any other underground structure, except that for drainage tile the minimum clearance may be less than 12 inches (305 millimeters) but not less than 2 inches (51 millimeters). However, where 12 inches (305 millimeters) of clearance is impracticable, the clearance may be reduced if adequate provisions are made for corrosion control.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.252 Backfilling.

Backfilling must be performed in a manner that protects any pipe coating and provides firm support for the pipe.

§ 195.254 Above ground components.

(a) Any component may be installed above ground in the following situations, if the other applicable requirements of this part are complied with:

- (1) Overhead crossings of highways, railroads, or a body of water.
- (2) Spans over ditches and gullies.
- (3) Scraper traps or block valves.
- (4) Areas under the direct control of the operator.
- (5) In any area inaccessible to the public.

(b) Each component covered by this section must be protected from the forces exerted by the anticipated loads.

§ 195.256 Crossing of railroads and highways.

The pipe at each railroad or highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads.

§ 195.258 Valves: General.

(a) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering.

(b) Each submerged valve located offshore or in inland navigable waters must be marked, or located by conventional survey techniques, to facilitate

quick location when operation of the valve is required.

§ 195.260 Valves: Location.

A valve must be installed at each of the following locations:

- (a) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.
- (b) On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.
- (c) On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.

(d) On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.

(e) On each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark unless the Administrator finds in a particular case that valves are not justified.

(f) On each side of a reservoir holding water for human consumption.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 23, 1982; Amdt. 195-50, 59 FR 17281, Apr. 12, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.262 Pumping equipment.

(a) Adequate ventilation must be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in the pumping station building.

(b) The following must be provided in each pump station:

- (1) Safety devices that prevent overpressuring of pumping equipment, including the auxiliary pumping equipment within the pumping station.
- (2) A device for the emergency shutdown of each pumping station.
- (3) If power is necessary to actuate the safety devices, an auxiliary power supply.

(c) Each safety device must be tested under conditions approximating actual

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operations and found to function properly before the pumping station may be used.

(d) Except for offshore pipelines, pumping equipment must be installed on property that is under the control of the operator and at least 15.2 m (50 ft) from the boundary of the pump station.

(e) Adequate fire protection must be installed at each pump station. If the fire protection system installed requires the use of pumps, motive power must be provided for those pumps that is separate from the power that operates the station.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-52, 59 FR 33397, June 28, 1994]

§ 195.264 Impoundment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks.

(a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tank.

(b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:

- (1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of impoundment must be in accordance with the following sections of NFPA 30:
 - (i) Impoundment around a breakout tank must be installed in accordance with Section 2-3.4.3; and
 - (ii) Impoundment by drainage to a remote impounding area must be installed in accordance with Section 2-3.4.2.
- (2) For tanks built to API Standard 2510, the installation of impoundment must be in accordance with Section 3 or 9 of API Standard 2510.

(c) Aboveground breakout tank areas must be adequately protected against unauthorized entry.

(d) Normal/emergency relief venting must be provided for each atmospheric pressure breakout tank. Pressure/vacuum-relieving devices must be provided for each low-pressure and high-pressure breakout tank.

(e) For normal/emergency relief venting and pressure/vacuum-relieving de-

ices installed on aboveground breakout tanks after October 2, 2000, compliance with paragraph (d) of this section requires the following for the tanks specified:

(1) Normal/emergency relief venting installed on atmospheric pressure tanks built to API Specification 12F must be in accordance with Section 4, and Appendices B and C, of API Specification 12F.

(2) Normal/emergency relief venting installed on atmospheric pressure tanks (such as those built to API Standard 650 or its predecessor Standard 12C) must be in accordance with API Standard 2000.

(3) Pressure-relieving and emergency vacuum-relieving devices installed on low pressure tanks built to API Standard 620 must be in accordance with Section 7 of API Standard 620 and its references to the normal and emergency venting requirements in API Standard 2000.

(4) Pressure and vacuum-relieving devices installed on high pressure tanks built to API Standard 2510 must be in accordance with Sections 5 or 9 of API Standard 2510.

[Amdt. 195-66, 64 FR 15935, Apr. 2, 1999]

§ 195.266 Construction records.

A complete record that shows the following must be maintained by the operator involved for the life of each pipeline facility:

- (a) The total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld.
- (b) The amount, location, and cover of each size of pipe installed.
- (c) The location of each crossing of another pipeline.
- (d) The location of each buried utility crossing.
- (e) The location of each overhead crossing.
- (f) The location of each valve and corrosion test station.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-34, 50 FR 34474, Aug. 26, 1985]

§ 195.300**Subpart E—Pressure Testing****§ 195.300 Scope.**

This subpart prescribes minimum requirements for the pressure testing of steel pipelines. However, this subpart does not apply to the movement of pipe under § 195.424.

[Amdt. 195-51, 59 FR 29384, June 7, 1994]

§ 195.302 General requirements.

(a) Except as otherwise provided in this section and in § 195.305(b), no operator may operate a pipeline unless it has been pressure tested under this subpart without leakage. In addition, no operator may return to service a segment of pipeline that has been replaced, relocated, or otherwise changed until it has been pressure tested under this subpart without leakage.

(b) Except for pipelines converted under § 195.5, the following pipelines may be operated without pressure testing under this subpart:

- (1) Any hazardous liquid pipeline whose maximum operating pressure is established under § 195.406(a)(5) that is—
- (i) An interstate pipeline constructed before January 8, 1971;
- (ii) An interstate offshore gathering line constructed before August 1, 1977;
- (iii) An intrastate pipeline constructed before October 21, 1985; or
- (iv) A low-stress pipeline constructed before August 11, 1994 that transports HVL.

(2) Any carbon dioxide pipeline constructed before July 12, 1991, that—

- (i) Has its maximum operating pressure established under § 195.406(a)(5); or
- (ii) Is located in a rural area as part of a production field distribution system.

(3) Any low-stress pipeline constructed before August 11, 1994 that does not transport HVL.

(4) Those portions of older hazardous liquid and carbon dioxide pipelines for which an operator has elected the risk-based alternative under § 195.303 and which are not required to be tested based on the risk-based criteria.

(c) Except for pipelines that transport HVL onshore, low-stress pipelines, and pipelines covered under § 195.303, the following compliance deadlines

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apply to pipelines under paragraphs (b)(1) and (b)(2)(i) of this section that have not been pressure tested under this subpart:

- (1) Before December 7, 1998, for each pipeline each operator shall—
- (i) Plan and schedule testing according to this paragraph; or
- (ii) Establish the pipeline's maximum operating pressure under § 195.406(a)(5).

(2) For pipelines scheduled for testing, each operator shall—

- (i) Before December 7, 2000, pressure test—
- (A) Each pipeline identified by name, symbol, or otherwise that existing records show contains more than 50 percent by mileage (length) of electric resistance welded pipe manufactured before 1970; and
- (B) At least 50 percent of the mileage (length) of all other pipelines; and
- (ii) Before December 7, 2003, pressure test the remainder of the pipeline mileage (length).

[Amdt. 195-51, 59 FR 29384, June 7, 1994, as amended by Amdt. 195-53, 59 FR 35471, July 12, 1994; Amdt. 195-51B, 61 FR 43027, Aug. 20, 1996; Amdt. 195-58, 62 FR 54592, Oct. 21, 1997; Amdt. 195-63, 63 FR 37506, July 13, 1998; Amdt. 195-65, 63 FR 59479, Nov. 4, 1998]

§ 195.303 Risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines.

(a) An operator may elect to follow a program for testing a pipeline on risk-based criteria as an alternative to the pressure testing in § 195.302(b)(1)(i)-(iii) and § 195.302(b)(2)(i) of this subpart. Appendix B provides guidance on how this program will work. An operator electing such a program shall assign a risk classification to each pipeline segment according to the indicators described in paragraph (b) of this section as follows:

- (1) Risk Classification A if the location indicator is ranked as low or medium risk, the product and volume indicators are ranked as low risk, and the probability of failure indicator is ranked as low risk;
- (2) Risk Classification B if the location indicator is ranked as high risk; or
- (3) Risk Classification C.

(b) An operator shall evaluate each pipeline segment in the program according to the following indicators of risk:

- (1) The location indicator is—

(1) The location indicator is—

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In conducting an engineering analysis an operator must consider the seam-related leak history of the pipe and pipe manufacturing information as available, which may include the pipe steel's mechanical properties, including fracture toughness; the manufacturing process and controls related to seam properties, including whether the ERW process was high-frequency or low-frequency, whether the weld seam was heat treated, whether the seam was inspected, the test pressure and duration during the mill hydrotest; the quality control of the steel-making process; and other factors pertinent to seam properties and quality.

(e) Pressure testing done under this section must be conducted in accordance with this subpart. Except for segments in Risk Classification B which are not constructed with pre-1970 ERW pipe, water must be the test medium.

(f) An operator electing to follow a program under paragraph (a) must develop plans that include the method of testing and a schedule for the testing by December 7, 1998. The compliance deadlines for completion of testing are as shown in the table below:

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Pipeline Segment	Risk classification	Test deadline
Pre-1970 Pipe susceptible to longitudinal seam failures (defined in § 195.303(c) & (d)).	C or B A	12/7/2000 12/7/2002
All Other Pipeline Segments.	C B A	12/7/2002 12/7/2004 Additional testing not required

(g) An operator must review the risk classifications for those pipeline segments which have not yet been tested under paragraph (a) of this section or otherwise inspected under paragraph (c) of this section at intervals not to exceed 15 months. If the risk classification of an untested or uninspected segment changes, an operator must take appropriate action within two years, or establish the maximum operating pressure under § 195.406(a)(5).

(h) An operator must maintain records establishing compliance with this section, including records verifying the risk classifications, the

(1) See Appendix B, Table C.

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plans and schedule for testing, the conduct of the testing, and the review of the risk classifications.

(i) An operator may discontinue a program under this section only after written notification to the Administrator and approval, if needed, of a schedule for pressure testing.

[Amdt. 195-65, 63 FR 59480, Nov. 4, 1998]

§ 195.304 Test pressure.

The test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during the test, for at least an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

[Amdt. 195-61, 59 FR 28384, June 7, 1994. Redesignated by Amdt. 195-65, 63 FR 59480, Nov. 4, 1998]

§ 195.305 Testing of components.

(a) Each pressure test under § 195.302 must test all pipe and attached fittings, including components, unless otherwise permitted by paragraph (b) of this section.

(b) A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either—

(1) The component was hydrostatically tested at the factory; or

(2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-51, 59 FR 29385, June 7, 1994; Amdt. 195-53, 59 FR 35471, July 12, 1994; Amdt. 195-51A, 59 FR 41260, Aug. 11, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.306 Test medium.

(a) Except as provided in paragraphs (b), (c), and (d) of this section, water must be used as the test medium.

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(b) Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if—

(1) The entire pipeline section under test is outside of cities and other populated areas;

(2) Each building within 300 feet (91 meters) of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;

(3) The test section is kept under surveillance by regular patrols during the test; and

(4) Continuous communication is maintained along entire test section.

(c) Carbon dioxide pipelines may use inert gas or carbon dioxide as the test medium if—

(1) The entire pipeline section under test is outside of cities and other populated areas;

(2) Each building within 300 feet (91 meters) of the test section is unoccupied while the test pressure is equal to or greater than a pressure that produces a hoop stress of 50 percent of specified minimum yield strength;

(3) The maximum hoop stress during the test does not exceed 80 percent of specified minimum yield strength;

(4) Continuous communication is maintained along entire test section; and

(5) The pipe involved is new pipe having a longitudinal joint factor of 1.00.

(d) Air or inert gas may be used as the test medium in low-stress pipelines.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-45, 56 FR 28226, June 12, 1991; Amdt. 195-51, 59 FR 29385, June 7, 1994; Amdt. 195-53, 59 FR 35471, July 12, 1994; Amdt. 195-51A, 59 FR 41260, Aug. 11, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.307 Pressure testing above-ground breakout tanks.

(a) For aboveground breakout tanks built to API Specification 12F and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of API Specification 12F.

(b) For aboveground breakout tanks built to API Standard 620 and first placed in service after October 2, 2000,

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hydrostatic and pneumatic testing must be in accordance with section 5.18 of API Standard 620.

(c) For aboveground breakout tanks built to API Standard 650 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.3 of API Standard 650.

(d) For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C that are returned to service after October 2, 2000, the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 10.3 of API Standard 653.

(e) For aboveground breakout tanks built to API Standard 2510 and first placed in service after October 2, 2000, pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.

[Amdt. 195-66, 64 FR 15836, Apr. 2, 1999]

§ 195.308 Testing of tie-ins.

Pipe associated with tie-ins must be pressure tested, either with the section to be tied in or separately.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by 195-51, 59 FR 29385, June 7, 1994]

§ 195.310 Records.

(a) A record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.

(b) The record required by paragraph (a) of this section must include:

- (1) The pressure recording charts;
- (2) Test instrument calibration data;
- (3) The name of the operator, the name of the person responsible for making the test, and the name of the test company used, if any;
- (4) The date and time of the test;
- (5) The minimum test pressure;
- (6) The test medium;
- (7) A description of the facility tested and the test apparatus;
- (8) An explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts; and

Subpart F—Operation and Maintenance**§ 195.400 Scope.**

This subpart prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe.

§ 195.401 General requirements.

(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under § 195.402(a) of this subpart.

(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(c) Except as provided in § 195.5, no operator may operate any part of any of the following pipelines unless it was designed and constructed as required by this part:

- (1) An interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid.
- (2) An interstate offshore gathering line, other than a low-stress pipeline, on which construction was begun after July 31, 1977, that transports hazardous liquid.
- (3) An intrastate pipeline, other than a low-stress pipeline, on which construction was begun after October 20, 1985, that transports hazardous liquid.
- (4) A pipeline on which construction was begun after July 11, 1991, that transports carbon dioxide.

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(5) A low-stress pipeline on which construction was begun after August 10, 1994.

[Amdt. 195-22, 46 FR 36360, July 27, 1981, as amended by Amdt. 195-33, 50 FR 15899, Apr. 23, 1985; Amdt. 195-33A, 50 FR 39008, Sept. 26, 1985; Amdt. 195-36, 51 FR 15008, Apr. 22, 1986; Amdt. 195-45, 56 FR 26926, June 12, 1991; Amdt. 195-53, 59 FR 35471, July 12, 1994]

§ 195.402 Procedural manual for operations, maintenance, and emergencies.

(a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

(b) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

(c) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(1) Making construction records, maps, and operating history available as necessary for safe operation and maintenance.

(2) Gathering of data needed for reporting accidents under subpart B of this part in a timely and effective manner.

(3) Operating, maintaining, and repairing the pipeline system in accordance with the requirements of this part.

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ance with each of the requirements of this subpart.

(4) Determining which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned.

(5) Analyzing pipeline accidents to determine their causes.

(6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section.

(7) Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within the limits prescribed by § 195.406, consider the hazardous liquid or carbon dioxide in transportation, variations in altitude along the pipeline, and pressure monitoring and control devices.

(8) In the case of a pipeline that is not equipped to fail safe, monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by § 195.406.

(9) In the case of facilities not equipped to fail safe that are identified under paragraph 195.402(c)(4) or that control receipt and delivery of the hazardous liquid or carbon dioxide, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location.

(10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with § 195.59 of this part.

(11) Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the

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potential exists for the presence of flammable liquids or gases.

(12) Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each government organization that may respond to a hazardous liquid or carbon dioxide pipeline emergency and acquaint the officials with the operator's ability in responding to a hazardous liquid or carbon dioxide pipeline emergency and means of communication.

(13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

(14) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

(d) *Abnormal operation.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device;

(v) Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Correcting variations from normal operation of pressure and flow equipment and controls.

(4) Notifying responsible operator personnel when notice of an abnormal operation is received.

(5) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedure

dures controlling abnormal operation and taking corrective action where deficiencies are found.

(e) *Emergencies.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs:

(1) Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action.

(2) Prompt and effective response to a notice of each type emergency, including fire or explosion occurring near or directly involving a pipeline facility accidental release of hazardous liquid or carbon dioxide from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities.

(3) Having personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency.

(4) Taking necessary action, such as emergency shutdown or pressure reduction, to minimize the volume of hazardous liquid or carbon dioxide that is released from any section of a pipeline system in the event of a failure.

(5) Control of released hazardous liquid or carbon dioxide at an accident scene to minimize the hazards, including possible intentional ignition in the cases of flammable highly volatile liquid.

(6) Minimization of public exposure to injury and probability of accident ignition by assisting with evacuation of residents and assisting with halting traffic on roads and railroads in the affected area, or taking other appropriate action.

(7) Notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline system transporting a highly volatile liquid.

(8) In the case of failure of a pipeline system transporting a highly volatile

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liquid, use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas.

(9) Providing for a post-accident review of employee activities to determine whether the procedures were effective in each emergency and taking corrective action where deficiencies are found.

(f) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 195.55.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-24, 47 FR 46852, Oct. 21, 1982; Amdt. 195-39, 53 FR 24951, July 1, 1988; Amdt. 195-45, 56 FR 26926, June 12, 1991; Amdt. 195-46, 56 FR 31090, July 9, 1991; Amdt. 195-49, 59 FR 6585, Feb. 11, 1994; Amdt. 195-55, 61 FR 18618, Apr. 26, 1996; Amdt. 195-59, 65 FR 54444, Sept. 8, 2000]

EFFECTIVE DATE NOTE: At 65 FR 54444, Sept. 8, 2000, § 195.402 was amended by revising paragraph (c)(10), effective Oct. 10, 2000. For the convenience of the user, the superseded text follows:

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(c) ***

(10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards.

* * * * *

§ 195.403 Training.

(a) Each operator shall establish and conduct a continuing training program to instruct operating and maintenance personnel to:

(1) Carry out the operating and maintenance, and emergency procedures established under § 195.402 that relate to their assignments;

(2) Know the characteristics and hazards of the hazardous liquids or carbon dioxide transported, including, in the case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions;

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(3) Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquids or carbon dioxide spills, and take appropriate corrective action;

(4) Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage; and

(5) Learn the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition.

(b) At the intervals not exceeding 15 months, but at least once each calendar year, each operator shall:

(1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section; and

(2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective.

(c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under § 195.402 for which they are responsible to ensure compliance.

[Amdt. 195-67, 64 FR 46866, Aug. 27, 1999]

§ 195.404 Maps and records.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:

(1) Location and identification of the following pipeline facilities:

(i) Breakout tanks;

(ii) Pump stations;

(iii) Scraper and sphere facilities;

(iv) Pipeline valves;

(v) Cathodically protected facilities;

(vi) Facilities to which § 195.402(c)(9) applies;

(vii) Rights-of-way; and

(viii) Safety devices to which § 195.428 applies.

(2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.

(3) The maximum operating pressure of each pipeline.

(4) The diameter, grade, type, and nominal wall thickness of all pipe.

(b) Each operator shall maintain for at least 3 years daily operating records that indicate—

(1) The discharge pressure at each pump station; and

(2) Any emergency or abnormal operation to which the procedures under § 195.402 apply.

(c) Each operator shall maintain the following records for the periods specified:

(1) The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe.

(2) The date, location, and description of each repair made to parts of the pipeline system other than pipe shall be maintained for at least 1 year.

(3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-34, 50 FR 34474, Aug. 26, 1985]

§ 195.405 Protection against ignitions and safe access/egress involving floating roofs.

(a) After October 2, 2000, protection provided against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with API Recommended Practice 2003, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 2003 is not necessary for the safety of a particular breakout tank.

(b) The hazards associated with access/egress onto floating roofs of service aboveground breakout tanks to perform inspection, service, maintenance or repair activities (other than specified general considerations, specified routine tasks or entering tanks removed from service for cleaning) are addressed in API Publication 2026. After October 2, 2000, the operator must review and consider the potentially hazardous conditions, safety practices and procedures in API Publication 2026 for inclusion in the procedure manual (§ 195.402(c)).

[Amdt. 195-66, 64 FR 15936, Apr. 2, 1999]

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§ 195.406**§ 195.406 Maximum operating pressure.**

(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

(1) The internal design pressure of the pipe determined in accordance with § 195.106. However, for steel pipe in pipelines being converted under § 195.5, if one or more factors of the design formula (§ 195.106) are unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5.0 of appendix N of ASME B31.8, reduced by the appropriate factors in §§ 195.106 (a) and (e); or

(ii) If the pipe is 12 3/4 inch (324 mm) or less outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.

(2) The design pressure of any other component of the pipeline.

(3) Eighty percent of the test pressure for any part of the pipeline which has been pressure tested under subpart E of this part.

(4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under § 195.305.

(5) For pipelines under §§ 195.302(b)(1) and (b)(2)(i) that have not been pressure tested under subpart E of this part, 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted.

(b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate

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controls and protective equipment to control the pressure within this limit.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-33, 50 FR 15899, Apr. 23, 1985; 50 FR 38680, Sept. 24, 1985; Amdt. 195-51, 59 FR 29385, June 7, 1994; Amdt. 195-52, 59 FR 33397, June 28, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998; Amdt. 195-65, 63 FR 59480, Nov. 4, 1998]

§ 195.408 Communications.

(a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.

(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:

(1) Monitoring operational data as required by § 195.402(c)(9);

(2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action;

(3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and

(4) Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.

§ 195.410 Line markers.

(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

(2) The marker must state at least the following on a background of sharply contrasting color:

(i) The word "Warning," "Caution," or "Danger" followed by the words

Research and Special Programs Administration, DOT**§ 195.414****§ 195.413 Underwater inspection and rebulb of pipelines in the Gulf of Mexico and its inlets.**

(a) Except for gathering lines of 4 1/2 inches (114 mm) nominal outside diameter or smaller, each operator shall, in accordance with this section, conduct an underwater inspection of its pipelines in the Gulf of Mexico and its inlets. The inspection must be conducted after October 3, 1989 and before November 16, 1992.

(b) If, as a result of an inspection under paragraph (a) of this section, or upon notification by any person, an operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802 of the location, and, if available, the geographic coordinates of that pipeline;

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is after November 1 of the year that the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

[Amdt. 195-47, 56 FR 63771, Dec. 5, 1991, as amended by Amdt. 195-52, 59 FR 33396, June 28, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.414 Cathodic protection.

(a) No operator may operate a hazardous liquid interstate pipeline after March 31, 1973, a hazardous liquid intrastate pipeline after October 19, 1988, or a carbon dioxide pipeline after July 12, 1993 that has an effective external surface coating material, unless that pipeline is cathodically protected. This paragraph does not apply to

"Petroleum (or the name of the hazardous liquid transported) Pipeline", or "Carbon Dioxide Pipeline," all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with an approximate stroke of 1/4 inch (6.4 millimeters).

(ii) The name of the operator and a telephone number (including area code) where the operator can be reached at all times.

(b) Line markers are not required for buried pipelines located—

(1) Offshore or at crossings of or under waterways and other bodies of water; or

(2) In heavily developed urban areas such as downtown business centers where—

(i) The placement of markers is impractical and would not serve the purpose for which markers are intended; and

(ii) The local government maintains current substructure records.

(c) Each operator shall provide line marking at locations where the line is above ground in areas that are accessible to the public.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-27, 48 FR 25208, June 6, 1983; Amdt. 195-54, 60 FR 14650, Mar. 20, 1995; Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.412 Inspection of rights-of-way and crossings under navigable waters.

(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way.

(b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-24, 47 FR 46852, Oct. 21, 1982; Amdt. 195-52, 59 FR 33397, June 28, 1994]

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breakout tank areas and buried pumping station piping. For the purposes of this subpart, a pipeline does not have an effective external coating, and shall be considered bare, if its cathodic protection current requirements are substantially the same as if it were bare.

(b) Each operator shall electrically inspect each bare hazardous liquid interstate pipeline, other than a low-stress pipeline, before April 1, 1975; each bare hazardous liquid intrastate pipeline, other than a low-stress pipeline, before October 20, 1990; each bare carbon dioxide pipeline before July 12, 1994; and each bare low-stress pipeline before July 12, 1996 to determine any areas in which active corrosion is taking place. The operator may not increase its established operating pressure on a section of bare pipeline until the section has been so electrically inspected. In any areas where active corrosion is found, the operator shall provide cathodic protection. Section 195.416(f) and (g) apply to all corroded pipe that is found.

(c) Each operator shall electrically inspect all breakout tank areas and buried pumping station piping on hazardous liquid interstate pipelines, other than low-stress pipelines, before April 1, 1973; on hazardous liquid intrastate pipelines, other than low-stress pipelines, before October 20, 1988; on carbon dioxide pipelines before July 12, 1994; and on low-stress pipelines before July 12, 1996 as to the need for cathodic protection, and cathodic protection shall be provided where necessary.

[Amdt. 195-45, 56 FR 26926, June 12, 1991, as amended by Amdt. 195-53, 59 FR 35471, July 12, 1994]

§ 195.416 External corrosion control.

(a) Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system that is under cathodic protection to determine whether the protection is adequate.

(b) Each operator shall maintain the test leads required for cathodic protection in such a condition that electrical measurements can be obtained to ensure adequate protection.

(c) Each operator shall, at intervals not exceeding 2½ months, but at least six times each calendar year, inspect each of its cathodic protection rectifiers.

(d) Each operator shall, at intervals not exceeding 5 years, electrically inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed.

(e) Whenever any buried pipe is exposed for any reason, the operator shall examine the pipe for evidence of external corrosion. If the operator finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extent of the corrosion.

(f) Any pipe that is found to be generally corroded so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must be replaced with coated pipe that meets the requirements of this part. However, generally corroded pipe need not be replaced if—

(1) The operating pressure is reduced to be commensurate with the limits on operating pressure specified in this subpart, based on the actual remaining wall thickness; or

(2) The pipe is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(g) If localized corrosion pitting is found to exist to a degree where leakage might result, the pipe must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness in the pits.

(h) The strength of the pipe, based on actual remaining wall thickness, for paragraphs (f) and (g) of this section may be determined by the procedure in ASME B31G manual for Determining the Remaining Strength of Corroded Pipelines or by the procedure developed by AGA/Battelle—A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk). Application of the procedure in the ASME B31G manual

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face for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the operator shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets the requirements of this part or, based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits on operating pressure specified in this subpart.

(i) For aboveground breakout tanks where corrosion of the tank bottom is controlled by a cathodic protection system, the cathodic protection system must be inspected to ensure it is operated and maintained in accordance with API Recommended Practice 651, unless the operator notes in the procedure manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of a particular breakout tank.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-20B, 46 FR 38922, July 30, 1981; Amdt. 195-24, 47 FR 46852, Oct. 21, 1982; Amdt. 195-45, 56 FR 26927, June 12, 1991]

§ 195.420 Valve maintenance.

(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

(b) Each operator shall, at intervals not exceeding 7½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

(c) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-24, 47 FR 46852, Oct. 21, 1982]

§ 195.422 Pipeline repairs.

(a) Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.

(b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

§ 195.424 Pipe movement.

(a) No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure.

(b) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are joined by welding unless—

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(1) Movement when the pipeline does not contain highly volatile liquids is impractical;

(2) The procedures of the operator under § 195.402 contain precautions to protect the public against the hazard in moving pipelines containing highly volatile liquids, including the use of warnings, where necessary, to evacuate the area close to the pipeline; and

(3) The pressure in that line section is reduced to the lower of the following:

(i) Fifty percent or less of the maximum operating pressure; or

(ii) The lowest practical level that will maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 p.s.i. (345 kPa) gage above the vapor pressure of the commodity.

(c) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are not joined by welding unless—

(1) The operator complies with paragraphs (b) (1) and (2) of this section; and

(2) That line section is isolated to prevent the flow of highly volatile liquid.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 46 FR 38922, July 30, 1981, as amended by Amdt. 195-63, 63 FR 37506, July 13, 1998]

§ 195.426 Scraper and sphere facilities.

No operator may use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982]

§ 195.428 Overpressure safety devices and overfill protection systems.

(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not

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to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

(b) In the case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years.

(c) Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Other aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed or significantly altered after October 2, 2000, must have an overfill protection system installed according to API Recommended Practice 2350. However, operators need not comply with any part of API Recommended Practice 2350 for a particular breakout tank if the operator notes in the manual required by § 195.402 why compliance with that part is not necessary for safety of the tank.

(d) After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-24, 47 FR 46852, Oct. 21, 1982; Amdt. 195-66, 64 FR 15936, Apr. 2, 1999]

§ 195.430 Firefighting equipment.

Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be—

(a) In proper operating condition at all times;

(b) Plainly marked so that its identity as firefighting equipment is clear; and

(c) Located so that it is easily accessible during a fire.

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the public, appropriate government organizations and persons engaged in excavation-related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and to report it to the operator or the fire, police, or other appropriate public officials. The program must be conducted in English and in other languages commonly understood by a significant community and concentration of non-English speaking population in the operator's operating areas.

[Amdt. 195-45, 56 FR 26927, June 12, 1991]

§ 195.442 Damage prevention program.

(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of above-ground structures by either explosive or mechanical means, and other earthmoving operations.

(b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of the responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under § 198.37 of this chapter; or

§ 195.432 Inspection of in-service breakout tanks.

(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.

(b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel above-ground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3).

(c) Each operator shall inspect the physical integrity of in-service steel above-ground breakout tanks built to API Standard 2510 according to section 6 of API 510.

(d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.

[Amdt. 195-66, 64 FR 15936, Apr. 2, 1999]

§ 195.434 Signs.

Each operator shall maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and an emergency telephone number to contact.

§ 195.436 Security of facilities.

Each operator shall provide protection for each pumping station and breakout tank area and other exposed facility (such as scraper traps) from vandalism and unauthorized entry.

§ 195.438 Smoking or open flames.

Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or the presence of flammable vapors.

§ 195.440 Public education.

Each operator shall establish a continuing educational program to enable

§ 195.444

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(2) The one-call system:

- Is operated in accordance with § 198.39 of this chapter;
- Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and

(iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

- Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.
- Provides for notification of the public in the vicinity of the pipeline and actual notification of persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:

- The program's existence and purpose; and
- How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

- The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and
- In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

- Pipelines located offshore.

(2) Pipelines to which access is physically controlled by the operator.

[Amdt. 195-54, 60 FR 14651, Mar. 20, 1995, as amended by Amdt. 195-50, 62 FR 61699, Nov. 19, 1997]

§ 195.444 CPM leak detection.

Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) must comply with API 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system.

[Amdt. 195-62, 63 FR 36376, July 6, 1998]

Subpart G

SOURCE: Amdt. 195-67, 64 FR 46866, Aug. 27, 1999, unless otherwise noted.

§ 195.501 Scope.

(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

(b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:

- Is performed on a pipeline facility;
- Is an operations or maintenance task;
- Is performed as a requirement of this part; and
- Affects the operation or integrity of the pipeline.

§ 195.503 Definitions.

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

- Indicate a condition exceeding design limits; or
- Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

- Written examination;
- Oral examination;
- Work performance history review;
- Observation during:
- Performance on the job.

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tasks shall be retained for a period of five years.

§ 195.509 General.

(a) Operators must have a written qualification program by April 27, 2001.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to August 27, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

APPENDIX A TO PART 195—DELINEATION BETWEEN FEDERAL AND STATE JURISDICTION—STATEMENT OF AGENCY POLICY AND INTERPRETATION

In 1979, Congress enacted comprehensive safety legislation governing the transportation of hazardous liquids by pipeline, the Hazardous Liquids Pipeline Safety Act of 1979, 49 U.S.C. 2001 *et seq.* (HLPESA). The HLPESA expanded the existing statutory authority for safety regulation, which was limited to transportation by common carriers in interstate and foreign commerce, to transportation through facilities used in or affecting interstate or foreign commerce. It also added civil penalty, compliance order, and injunctive enforcement authorities to the existing criminal sanctions. Modeled largely on the Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. 1671 *et seq.* (NGPSA), the HLPESA provides for a national hazardous liquid pipeline safety program with nationally uniform minimal standards and with enforcement administered through a Federal-State partnership. The HLPESA leaves to exclusive Federal regulation and enforcement the "interstate pipeline facilities," those used for the pipeline transportation of hazardous liquids in interstate or foreign commerce. For the remainder of the pipeline facilities, denominated "intrastate pipeline facilities," the HLPESA provides that the same Federal regulation and enforcement will apply unless a State certifies that it will assume those responsibilities. A certified State must adopt the same minimal standards but may adopt additional more stringent standards so long as they are compatible. Therefore, in States which participate in the hazardous liquid pipeline safety program through certification, it is necessary to distinguish the interstate from the intrastate pipeline facilities.

In deciding that an administratively practical approach was necessary in distinguishing between interstate and intrastate

(f) On the job training; or

(g) Simulations; or

Qualified means that an individual has been evaluated and can:

- Perform assigned covered tasks and
- Recognize and react to abnormal operating conditions.

§ 195.505 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

- Identify covered tasks;
- Ensure thorough evaluation that individuals performing covered tasks are qualified;
- Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in Part 195;

(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(f) Communicate changes that affect covered tasks to individuals performing those covered tasks; and

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.

§ 195.507 Recordkeeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:

- Identification of qualified individual(s);
- Identification of the covered tasks the individual is qualified to perform;
- Date(s) of current qualification; and

(b) Qualification method(s).

(c) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered

D" (in State Y). DOT will rely on the FERC filing as indication of interstate commerce.

Example 5. Same as in example 1 except that the line between "Point C" and "Point D" has a lateral line connected to it. The lateral is located entirely with State X. DOT will rely on the existence or non-existence of a FERC filing covering transportation over that lateral as determinative of interstate commerce.

Example 6. Same as in example 1 except that the certified agency in State X has brought an enforcement action (under the pipeline safety laws) against P because of its operation of the line between "Point A" and "Point B". P has successfully defended against the action on jurisdictional grounds. DOT will assume jurisdiction if necessary to avoid the anomaly of a pipeline subject to neither State or Federal safety enforcement. DOT's assertion of jurisdiction in such a case would be based on the gap in the state's enforcement authority rather than a DOT decision that the pipeline is an interstate pipeline facility.

Example 7. Pipeline Company P operates a pipeline that originates on the Outer Continental Shelf. P does not file any tariff for that line with FERC. DOT will consider the pipeline to be an interstate pipeline facility.

Example 8. Pipeline Company P is constructing a pipeline from "Point C" (in State X) to "Point D" (in State Y). DOT will consider the pipeline to be an interstate pipeline facility.

Example 9. Pipeline company P is constructing a pipeline from "Point C" to "Point B" (both in State X) but intends to file tariffs with FERC in the transportation of hazardous liquid in interstate commerce. Assuming there is some connection to an interstate pipeline facility, DOT will consider this line to be an interstate pipeline facility.

Example 10. Pipeline Company P has operated a pipeline subject to FERC economic regulation. Solely because of some statutory economic deregulation, that pipeline is no longer regulated by FERC. DOT will continue to consider that pipeline to be an interstate pipeline facility.

As seen from the examples, the types of situations in which DOT will not defer to the FERC regulatory scheme are generally clear-cut cases. For the remainder of the situations where variation from the FERC scheme would require DOT to replicate the forum already provided by FERC and to consider economic

TABLE 1. TEST REQUIREMENTS—MAINLINE SEGMENTS OUTSIDE OF TERMINALS, STATIONS, AND TANK FARMS

Pipeline segment	Risk classification	Test deadline ¹	Test medium
Pre-1970 Pipeline Segments susceptible to longitudinal seam failures ²	C or B	12/7/2000 ³	Water only.
All Other Pipeline Segments	A C B	12/7/2002 ³ 12/7/2002 ⁴ 12/7/2004 ⁴	Water only. Water only. Water/Liq. ⁵

tion that is needed to make decisions of this nature than can DOT.

In delineating which liquid pipeline facilities are interstate pipeline facilities within the meaning of the HLPFA, DOT will generally rely on the FERC filings; that is, if there is a tariff or concurrence filed with FERC governing the transportation of hazardous liquids over a pipeline facility or if there has been an exemption from the obligation to file tariffs obtained from FERC, then DOT will, as a general rule, consider the facility to be an interstate pipeline facility within the meaning of the HLPFA. The types of situations in which DOT will ignore the existence or non-existence of a filing with FERC will be limited to those cases in which it appears obvious that a complaint filed with FERC would be successful or in which blind reliance on a FERC filing would result in a situation clearly not intended by the HLPFA such as a pipeline facility not being subject to either State or Federal safety regulation. DOT anticipates that the situations in which there is any question about the validity of the FERC filings as a ready reference will be few and that the actual variations from reliance on those filings will be rare. The following examples indicate the types of facilities which DOT believes are interstate pipeline facilities subject to the HLPFA despite the lack of a filing with FERC and the types of facilities over which DOT will generally defer to the jurisdiction of a certifying state despite the existence of a filing with FERC.

Example 1. Pipeline company P operates a pipeline from "Point A" located in State X to "Point B" (also in X). The physical facilities never cross a state line and do not connect with any other pipeline which does cross a state line. Pipeline company P also operates another pipeline between "Point C" in State X and "Point D" in an adjoining State Y. Pipeline company P files a tariff with FERC for transportation from "Point A" to "Point B" as well as for transportation from "Point C" to "Point D." DOT will ignore filing for the line from "Point A" to "Point B" and consider the line to be intrastate.

Example 2. Same as in example 1 except that P does not file any tariffs with FERC. DOT will assume jurisdiction of the line between "Point C" and "Point D."

Example 3. Same as in example 1 except that P files its tariff for the line between "Point C" and "Point D" not only with FERC but also with State X. DOT will rely on the FERC filing as indication of interstate commerce.

Example 4. Same as in example 1 except that the pipeline from "Point A" to "Point B" (in State X) connects with a pipeline operated by another company transports liquid between "Point B" (in State X) and "Point

liquid pipeline facilities and in determining how best to accomplish this, DOT has logically examined the approach used in the NGPSA. The NGPSA defines the interstate gas pipeline facilities subject to exclusive Federal jurisdiction as those subject to the economic regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC). Experience has proven this approach practical. Unlike the NGPSA however, the HLPFA has no specific reference to FERC jurisdiction, but instead defines interstate liquid pipeline facilities by the more commonly used means of specifying the end points of the transportation involved. For example, the economic regulatory jurisdiction of FERC over the transportation of both gas and liquids by pipeline is defined in much the same way. In implementing the HLPFA DOT has sought a practicable means of distinguishing between interstate and intrastate pipeline facilities that provide the requisite degree of certainty to Federal and State enforcement personnel and to the regulated entities. DOT intends that this statement of agency policy and interpretation provide that certainty.

In 1981, DOT decided that the inventory of liquid pipeline facilities identified as subject to the jurisdiction of FERC approximates the HLPFA category of "interstate pipeline facilities." Administrative use of the FERC inventory has the added benefit of avoiding the creation of a separate Federal scheme for determination of jurisdiction over the same regulated entities. DOT recognizes that the FERC inventory is only an approximation and may not be totally satisfactory without some modification. The difficulties stem from some significant differences in the economic regulation of liquid and of natural gas pipelines. There is an affirmative assertion of jurisdiction by FERC over natural gas pipelines through the issuance of certificates of public convenience and necessity prior to commencing operations. With liquid pipelines, there is only a rebuttable presumption of jurisdiction created by the filing by pipeline operators of tariffs (or concurrences) for movement of liquids through existing facilities. Although FERC does police the filings for such matters as compliance with the general duties of common carriers, the question of jurisdiction is normally aired upon complaint. While any person, including State or Federal agencies, can avail themselves of the FERC forum by use of the complaint process, that process has only been rarely used to review jurisdictional matters (probably because of the infrequency of real disputes on the issue). Where the issue has arisen, the reviewing body has noted the need to examine various criteria primarily of an economic nature. DOT believes that, in most cases, the formal FERC forum can better receive and evaluate the type of informa-

TABLE 1. TEST REQUIREMENTS—MAINLINE SEGMENTS OUTSIDE OF TERMINALS, STATIONS, AND TANK FARMS—Continued

Pipeline segment	Risk classification	Test deadline ¹	Test medium
	A	Additional pressure testing not required.	

¹ If operational experience indicates a history of past failures for a particular pipeline segment, failure causes (time-dependent defects due to corrosion, construction, manufacture, or transmission problems, etc.) shall be reviewed in determining risk classification (See Table 6) and the timing of the pressure test should be accelerated.

² All pre-1970 ERW pipeline segments may not require testing. Testing is required for which ERW pipeline segments should be included in this category, an operator must consider the following factors: (1) the age of the pipeline; (2) the manufacturing process as available; (3) the operating history of the pipeline; (4) the physical properties, including fracture toughness; the manufacturing process and control; (5) the testing history, including whether the ERW process was high-frequency or low-frequency; whether the pipeline was heat treated; whether the seam was inspected; the test pressure and duration during mill hydrotest; the quality control of the steel-making process; and other factors pertinent to seam properties and quality.

³ For those pipeline operators with extensive mileage of pre-1970 ERW pipe, any waiver requests for timing relief should be supported by an assessment of hazards with location, product, volume, and probability of failure considerations consistent with Tables 3, 4, 5, and 6.

⁴ A magnetic flux leakage or ultrasonic internal inspection survey may be utilized as an alternative to pressure testing where leak history and operating experience do not indicate leaks caused by longitudinal cracks or seam failures.

⁵ Pressure tests utilizing a hydrocarbon liquid may be conducted, but only with a liquid which does not vaporize rapidly.

Using LOCATION, PRODUCT, VOLUME, factor which determines overall risk, and FAILURE HISTORY "Indicators" from the PRODUCT, VOLUME, and PROB- Tables 3, 4, 5, and 6 respectively, the overall ABILITY OF FAILURE Indicators used to risk classification of a given pipeline or pipe- line segment can be established from Table 2. The LOCATION Indicator is the primary

TABLE 2.—RISK CLASSIFICATION

Risk classification	Hazard location indicator	Product/volume indicator	Probability of failure indicator
A	L or M	L/A	L
B	H	Not A or C Risk Classification	Any.
C		Any	Any.

H=High M=Moderate L=Low

NOTE: For Location, Product, Volume, and Probability of Failure Indicators, see Tables 3, 4, 5, and 6.

Table 3 is used to establish the LOCATION ciated with a pipeline facility's location, a Indicator used in Table 2. Based on the popu- LOCATION Indicator of H, M or L is se- lation and environment characteristics asso- lected.

TABLE 3.—LOCATION INDICATORS—PIPELINE SEGMENTS

Indicator	Population ¹	Environment ²
H	Non-rural areas	Environmentally sensitive ² areas.
M	Rural areas	Not environmentally sensitive ² areas.
L		

¹ The effects of potential vapor migration should be considered for pipeline segments transporting highly volatile or toxic prod- ucts.

² We expect operators to use their best judgment in applying this factor.

Tables 4, 5 and 6 are used to establish the product transported. The VOLUME Indicator PRODUCT, VOLUME, and PROBABILITY is selected from Table 5 as H, M, or L based OF FAILURE Indicators respectively. In on the nominal diameter of the pipeline. The Table 2. The PRODUCT Indicator is selected Probability of Failure Indicator is selected from Table 4 as H, M, or L based on the acute and chronic hazards associated with the

TABLE 4.—PRODUCT INDICATORS

Indicator	Considerations	Product examples
H	(Highly volatile and flammable)	(Propane, butane, Natural Gas Liquid (NGL), ammonia)

TABLE 4.—PRODUCT INDICATORS—Continued

Indicator	Considerations	Product examples
M	Highly toxic Flammable—flashpoint <100F Non-flammable—flashpoint 100+F	(Benzene, high Hydrogen Sulfide con- tent crude oils). (Gasoline, JP4, low flashpoint crude oils). (Diesel, fuel oil, kerosene, JP5, most crude oils). Carbon Dioxide.
L	Highly volatile and non-flammable/non-toxic.	

Considerations: The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flam- mability, and water solubility determine the Product Indicator. Comprehensive Environ- mental Response, Compensation and Liabil- ity Act Reportable Quantity values can be used as an indication of chronic toxicity. Na- tional Fire Protection Association health factors can be used for rating acute hazards.

Sec.
198.1 Scope.
198.3 Definitions.

Subpart A—General

198.11 Grant authority.
198.13 Grant allocation formula.

Subpart B—Grant Allocation

198.31 Scope.

198.33 [Reserved]
198.35 Grants conditioned on adoption of one-call damage prevention program.
198.37 State one-call damage prevention program.
198.39 Qualifications for operation of one-call notification system.

AUTHORITY: 49 U.S.C. 60106, 60106, 60114; and 49 CFR 1.53.

SOURCE: 55 FR 38691, Sept. 20, 1990, unless otherwise noted.

Subpart A—General

§ 198.1 Scope.

This part prescribes regulations gov- erning grants-in-aid for State pipeline safety compliance programs.

§ 198.3 Definitions.

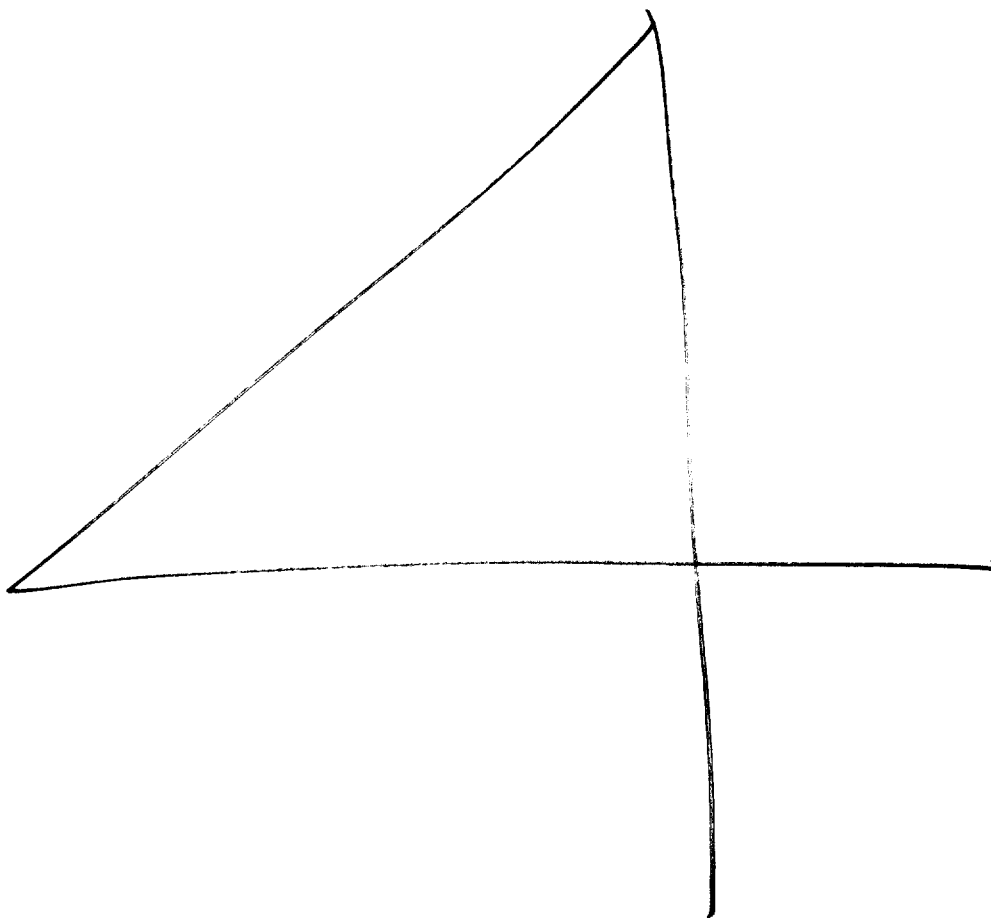
As used in this part:

Adopt means establish under State law by statute, regulation, license, cer- tification, order, or any combination of these legal means.

Excavation activity means an exca- vation activity defined in §192.614(a) of this chapter, other than a specific ac- tivity the State determines would not

PARTS 196-197—[RESERVED]

[Amtd. 195-65, 63 FR 59480, Nov. 4, 1998; 64 FR 6815, Feb. 11, 1999]



IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

AFFIDAVIT OF P.D. HAMILTON

STATE OF TEXAS §
 §
COUNTY OF TRINITY §

Before me, the undersigned authority, on this day personally appeared P.D. Hamilton, who
being by me duly sworn, deposed and said:

1. My name is P.D. Hamilton. I am over 21 years of age, have never been convicted of a felony, and am competent to make this affidavit. I have personal knowledge of the facts stated herein, and they are true and correct.

2. I am the Trustee of the Prentice Dell Hamilton and Florine Hamilton Family Trust (the "Trust") which owns property in Trinity County, Texas (the "property").

3. The property consists of approximately 420 acres and is used by me for a commercial cattle operation, including mixed and Semmental-Angus cross bred cattle.

4. My family and I also use the property for recreation and hunting. My children and grandchildren have spent time with me on the property. There is also a camp house on the property that is used to sleep overnight.

5. There is a deer lease on the property and I lease the property to other individuals for hunting.

6. Prior to February 2001, I became concerned about the condition of Koch pipelines running through my family's property. Based upon the sign markers for the pipelines, I am aware that the pipelines are transporting liquid petroleum gas and natural gas which can cause a fire or explosion. Based upon the sign markers for the pipelines, I am also aware that the pipelines are owned or operated by Koch Pipeline.

7. Because it appears that the ground over or around the pipelines may have eroded or settled, I was concerned that the pipelines might be exposed or not buried deep enough underground to be safe. I was also concerned about whether the pipelines are properly marked, whether the pipelines have any leaks, whether the pipelines themselves have sufficient integrity to be safe, whether the pipelines are being operated safely, whether any inspections of the pipelines are being conducted, and what action should be taken if the pipelines ruptured or leaked. The only information I recall receiving from Koch regarding any pipeline and/or any emergency that may result because of a pipeline is a calendar that was received approximately three years ago.

8. Prior to June 2001, I learned additional information regarding Koch's pipelines, including that a Koch pipeline in Kaufman County, Texas exploded killing two individuals. I learned that the Koch pipeline in Kaufman County, Texas transported liquid petroleum gas and ruptured because of corrosion. I also became aware that Koch has had other problems with the safety of its pipelines, including that the United States filed suit against Koch because of numerous oil spills from its pipelines.

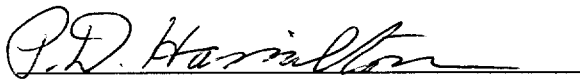
9. I am aware that an inspection of the Koch pipelines that run through my family's property has been conducted. This inspection confirms that the liquid petroleum gas pipeline is buried less than 30 inches deep in some locations. This inspection also confirmed that the natural gas pipeline is buried as shallow as 8 and 15 inches below ground in some locations. Further, this inspection confirmed that these pipelines are not properly marked.

10. I do not believe the Koch pipelines that run through my family's property are safe based upon the appearance of erosion or settling of the ground over or around the pipelines, the shallow depth of the pipelines in some locations on the property, the inaccurate markers, the lack of information received from Koch about the pipelines and what to do if an emergency arises, and the information learned about Koch's prior pipeline leaks and ruptures.

11. I am very concerned the Koch pipelines that run through my family's property may leak or rupture, resulting in a fire or explosion that may injure me, my family, or any other individuals who may be on the property. Because of my concerns, worry and fear about the pipelines' safety, I have limited the use of that part of the property where the pipelines are located. For example, my family and I do not use that part of the property for recreation. Because I am

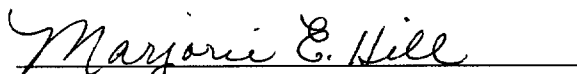
concerned about the depth of the pipelines and inaccurate markers, I do not perform the same work, such as subsoiling, on that part of the property as I do for the other part of the land. I may also have to limit the use of that part of the property where the pipelines are located for hunting. I believe the Koch pipelines expose me and my family to imminent risk of harm.

FURTHER AFFIANT SAYETH NOT.


P.D. Hamilton

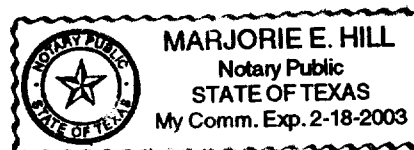
STATE OF TEXAS §
 §
COUNTY OF TRINITY §

SUBSCRIBED AND SWORN TO before me by the said P.D. Hamilton on the 25th day of September, 2001.


Notary Public in and for the State of Texas

My Commission Expires:

February 18, 2003



S

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

**P.D. HAMILTON, Individually and as
Trustee of the Prentice Dell Hamilton and
Florine Hamilton Family Trust**

VS.

CIVIL ACTION NO. 9:01CV132

KOCH INDUSTRIES, INC., Individually
and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
GS PIPELINE COMPANY, L.L.C.,
ENTERGY-KOCH, L.P., and
EKLP, L.L.C.

AFFIDAVIT OF TANNIS STONE

[illegible]

Before me, the undersigned authority, on this day personally appeared Tannis Stone, who being by me duly sworn, deposed and said:

1. "My name is Tannis Stone. I am over 21 years of age, have never been convicted of a felony, and am competent to make this affidavit. I have personal knowledge of the facts stated herein, and they are true and correct.

2. "I am a legal assistant for R. Michael McCauley and an employee of the law firm of McCauley, Macdonald & Devin, P.C.

3. "R. Michael McCauley is an attorney of record for Plaintiff P.D. Hamilton, individually and as Trustee of the Prentice Dell Hamilton and Florine Hamilton Family Trust ("Hamilton") and, pursuant to Local Rule CV-11, is designated as the Attorney-in-Charge for Hamilton.

4. "Attached in an Appendix to Plaintiff's Response to the Koch Defendants' Motion to Dismiss are true and correct copies of the following documents which I obtained as public records from the files of the Texas Railroad Commission:

- a. Texas Railroad Commission Permit to Operate Pipeline No. 04518;
- b. Texas Railroad Commission Permit to Operate Pipeline No. 01992;
- c. Texas Railroad Commission Permit to Operate Pipeline No. 00561;
- d. Texas Railroad Commission Permit to Operate Pipeline No. 01700;
- e. Texas Railroad Commission Permit to Operate Pipeline No. 00761;
- f. OPS Warning Letter to Koch Gateway Pipeline Company dated September 30, 1998;
- g. OPS Warning Letter to Koch Gateway Pipeline Company dated October 8, 1998; and
- h. OPS Warning Letter to Koch Gateway Pipeline Company dated April 15, 1998."

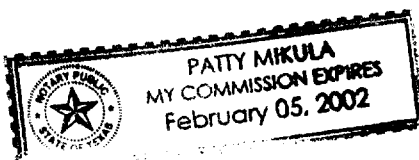
FURTHER AFFIANT SAYETH NOT.

Tannis Stone

Tannis Stone

STATE OF TEXAS §
 §
COUNTY OF DALLAS §

SUBSCRIBED AND SWORN TO before me by the said Tannis Stone on the 26th day of September, 2001.



Patty Mikula

Notary Public in and for the State of Texas

My Commission Expires:

2/05/02

RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION
PIPELINE SAFETY SECTION

PERMIT TO OPERATE PIPELINE

Austin, Texas, October 12, 1995

KOCH PIPELINE COMPANY, L.P.
P O BOX 29
MEDFORD

OK 73759

Permit No. 04518
FLUID TRANSPORTED
Crude/Condensate
Gas
Products XXX *
Other

This is to certify that KOCH PIPELINE COMPANY, L.P. has
complied with Rule 70 of the Commission Rules and Regulations
governing pipelines in accordance with Article 6018 et seq. R.C.S.,
and is granted this permit by the Commission to operate the
following line or lines located at:

ANDERSON
GRAYSON
KAUFMAN
TRINITY

CHAMBERS
HENDERSON
LIBERTY
VAN ZANDT

COLLIN
HOUSTON
POLK

FANNIN
HUNT
SAN JACINTO

PERMIT AMENDED TO REFLECT OPERATOR NAME CHANGE FROM KOCH
PIPELINES, INC.

This permit is valid until the operating ownership of such line
or system changes, or until extensions or other physical changes
are made in the line or system. (See Instructions on Form T-4.)

RAILROAD COMMISSION OF TEXAS

BY

Kathy Arnold

RECEIVED
R.R.C. OF TEXAS

JUN 16 2000

Form T-4C
(4/97)RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION
PIPELINE SAFETY SECTIONGAS SERVICES DIVISION
AUSTIN, TEXAS

PIPELINE AND GATHERING SYSTEM FORM OF CERTIFICATION

Company/Address KOCH PIPELINE COMPANY, L.P. P.O. BOX 29 MEDFORD OK 73759		Permit No. 04518	P-5 No. 473732																								
PIPELINE CLASSIFICATION Common Carrier <input checked="" type="checkbox"/> Interstate <input checked="" type="checkbox"/> Gas Utility <input type="checkbox"/> Intrastate <input type="checkbox"/> Private <input type="checkbox"/> Issuance Date of Last Permit <u>6-3-99</u> Location of Line(s) by County(s) <u>Chambers, Liberty,</u> <u>San Jacinto, Polk, Trinity, Houston,</u> <u>Anderson, Henderson, Van Zandt, Kaufman,</u> <u>Hunt, Collin, Fannin and Grayson Counties</u>		PLEASE ANSWER (A) & (B) <table border="0"> <thead> <tr> <th></th> <th>(A) Fluid Transported</th> <th>(B) Miles of Pipe</th> </tr> </thead> <tbody> <tr> <td>Crude</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Condensate</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Gas *</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Products *</td> <td><input checked="" type="checkbox"/></td> <td>309.72</td> </tr> <tr> <td>Full Oil Well Stream</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Full Gas Well Stream</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Other *</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> </tbody> </table> *Specify _____ Does fluid contain H ₂ S? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No If yes, at what concentration? _____ ppm			(A) Fluid Transported	(B) Miles of Pipe	Crude	<input type="checkbox"/>	_____	Condensate	<input type="checkbox"/>	_____	Gas *	<input type="checkbox"/>	_____	Products *	<input checked="" type="checkbox"/>	309.72	Full Oil Well Stream	<input type="checkbox"/>	_____	Full Gas Well Stream	<input type="checkbox"/>	_____	Other *	<input type="checkbox"/>	_____
	(A) Fluid Transported	(B) Miles of Pipe																									
Crude	<input type="checkbox"/>	_____																									
Condensate	<input type="checkbox"/>	_____																									
Gas *	<input type="checkbox"/>	_____																									
Products *	<input checked="" type="checkbox"/>	309.72																									
Full Oil Well Stream	<input type="checkbox"/>	_____																									
Full Gas Well Stream	<input type="checkbox"/>	_____																									
Other *	<input type="checkbox"/>	_____																									

This will certify that the installations described above have not been subject to any modifications, extensions or abandonments since the issuance date of last permit.

REMARKS: _____

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein true, correct, and complete, to the best of my knowledge.

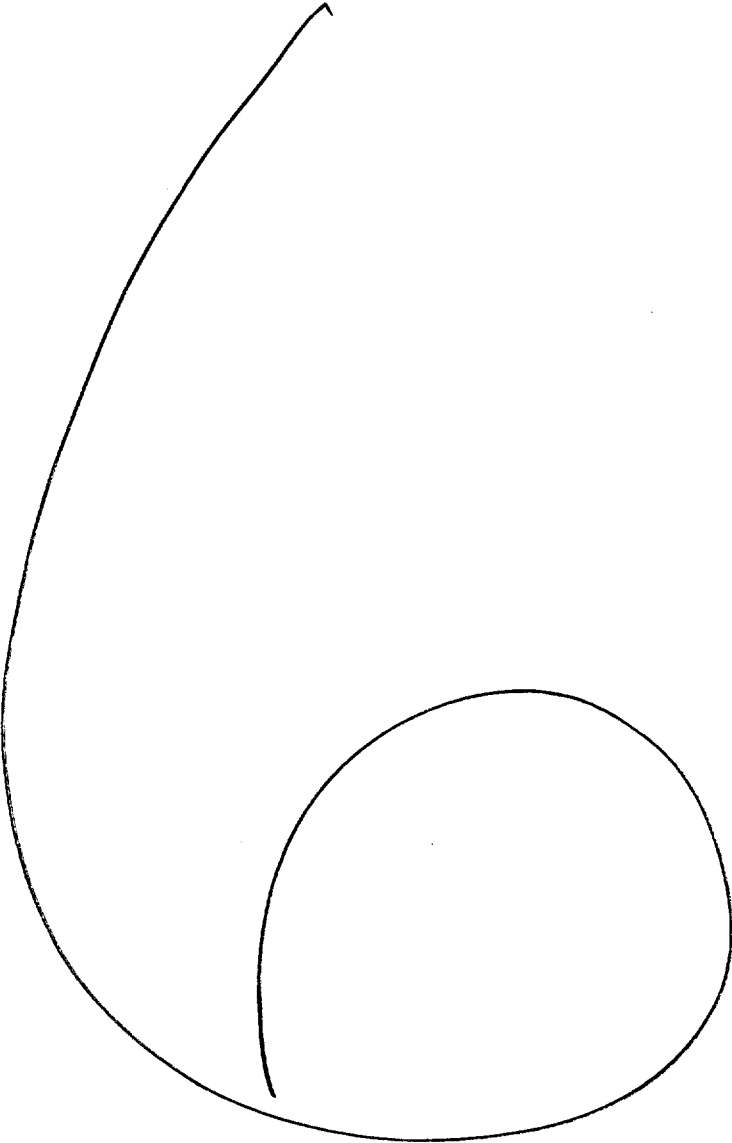
Bob Aebi
Signature

Bob Aebi
Name of Person (type or print)

5-25-00 Regulation Coordinator
Date Title

Telephone Number 580 395-6294
Area Code Number

Please mail **completed** Form T-4c to Railroad Commission of Texas, Gas Services Division / Pipeline Safety, P. O. Box 129 Austin, TX 78711-2967. If you have questions call (512) 463-7194.



Koch Pip
April 1

PIPELINE LOG
00761 Koch C
01438 Koch H
03974 Koch H
00561 Koch F
01700 Koch F
01992 Koch F
04618 Koch F
04638 Koch F

RRCH 00862



Prepaid
Railroad Comm
Gas Service

RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION
PIPELINE SAFETY SECTION

PERMIT TO OPERATE PIPELINE
Austin, Texas, October 12, 1995

KOCH PIPELINE COMPANY, L.P.
P O BOX 29
MEDFORD

OK 73759

Permit No. 01992
FLUID TRANSPORTED
Crude/Condensate
Gas
Products XXX NGL
Other

This is to certify that KOCH PIPELINE COMPANY, L.P. has
complied with Rule 70 of the Commission Rules and Regulations
governing pipelines in accordance with Article 6018 et seq. R.C.S.,
and is granted this permit by the Commission to operate the
following line or lines located at:

CHAMBERS
GRIMES
LIBERTY
NUECES
WISE

COLLIN
HENDERSON
MADISON
ROCKWALL

DENTON
KAUFMAN
MONTGOMERY
SAN JACINTO

FREESTONE
LEON
NAVARRO
WALKER

PERMIT AMENDED TO REFLECT OPERATOR NAME CHANGE FROM KOCH
PIPELINES, INC.

This permit is valid until the operating ownership of such line
or system changes, or until extensions or other physical changes
are made in the line or system. (See Instructions on Form T-4.)

RAILROAD COMMISSION OF TEXAS

BY Kathy Arnold

Form T-4A

KP/B 046100

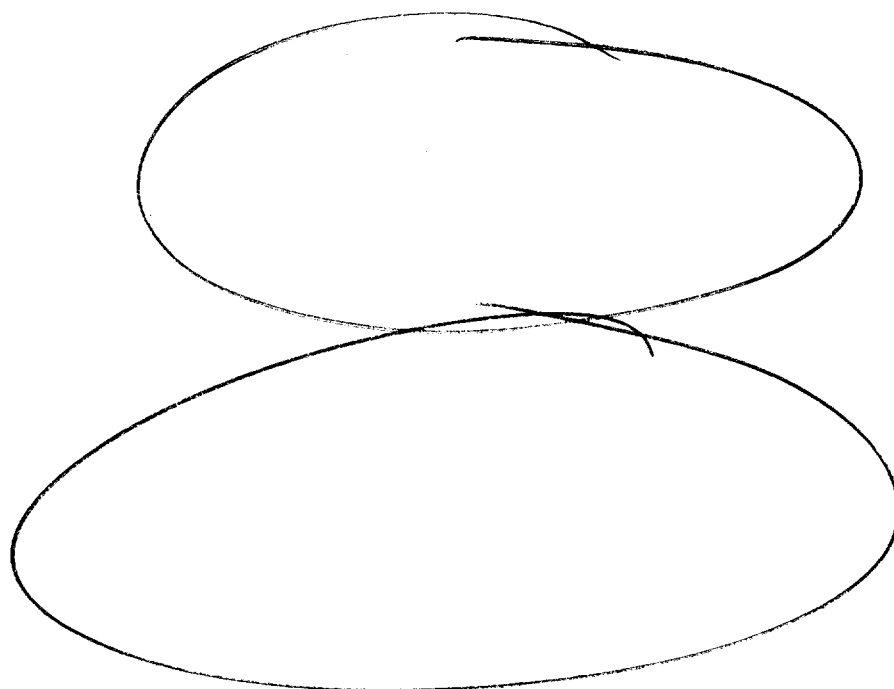
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TOTAL P.02



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R.R.C. OF TEXAS

JUN 18 2000

RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION
PIPELINE SAFETY SECTION
GAS SERVICES DIVISION
AUSTIN, TEXASForm T-4C
(4/97)

PIPELINE AND GATHERING SYSTEM FORM OF CERTIFICATION

Company/Address KOCH PIPELINE COMPANY, L.P. DIAMOND KOCH II, L.P. P.O. BOX 29 MEDFORD, OKLAHOMA 73759		Permit No. 00561	P-5 No. 217017																								
PIPELINE CLASSIFICATION Common Carrier <input checked="" type="checkbox"/> Interstate <input checked="" type="checkbox"/> Gas Utility <input type="checkbox"/> Intrastate <input type="checkbox"/> Private <input type="checkbox"/> Issuance Date of Last Permit <u>3-11-99</u> Location of Line(s) by County(s) <u>Andrews, Bell, Borden,</u> <u>Brazos, Brown, Callahan, Chambers,</u> <u>Comanche, Coryell, Ector, Falls, Fisher,</u> <u>Grimes, HAMILITON, Harris, Howard, Liberty,</u> <u>Martin, McLennan, Midland, Milam, Montgomery,</u> <u>Nolan, Robertson, Scurry, Taylof, Winkler,</u> <u>and Yoakum Counties</u>		PLEASE ANSWER (A) & (B) <table border="1"> <thead> <tr> <th></th> <th>(A) Fluid Transported</th> <th>(B) Miles of Pipe</th> </tr> </thead> <tbody> <tr> <td>Crude</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Condensate</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Gas *</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Products *</td> <td><input checked="" type="checkbox"/></td> <td>829.4</td> </tr> <tr> <td>Full Oil Well Stream</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Full Gas Well Stream</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Other *</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> </tbody> </table> Does fluid contain H ₂ S? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No If yes, at what concentration? _____ ppm			(A) Fluid Transported	(B) Miles of Pipe	Crude	<input type="checkbox"/>	_____	Condensate	<input type="checkbox"/>	_____	Gas *	<input type="checkbox"/>	_____	Products *	<input checked="" type="checkbox"/>	829.4	Full Oil Well Stream	<input type="checkbox"/>	_____	Full Gas Well Stream	<input type="checkbox"/>	_____	Other *	<input type="checkbox"/>	_____
	(A) Fluid Transported	(B) Miles of Pipe																									
Crude	<input type="checkbox"/>	_____																									
Condensate	<input type="checkbox"/>	_____																									
Gas *	<input type="checkbox"/>	_____																									
Products *	<input checked="" type="checkbox"/>	829.4																									
Full Oil Well Stream	<input type="checkbox"/>	_____																									
Full Gas Well Stream	<input type="checkbox"/>	_____																									
Other *	<input type="checkbox"/>	_____																									

This will certify that the installations described above have not been subject to any modifications, extensions or abandonments since the issuance date of last permit.

REMARKS: _____

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

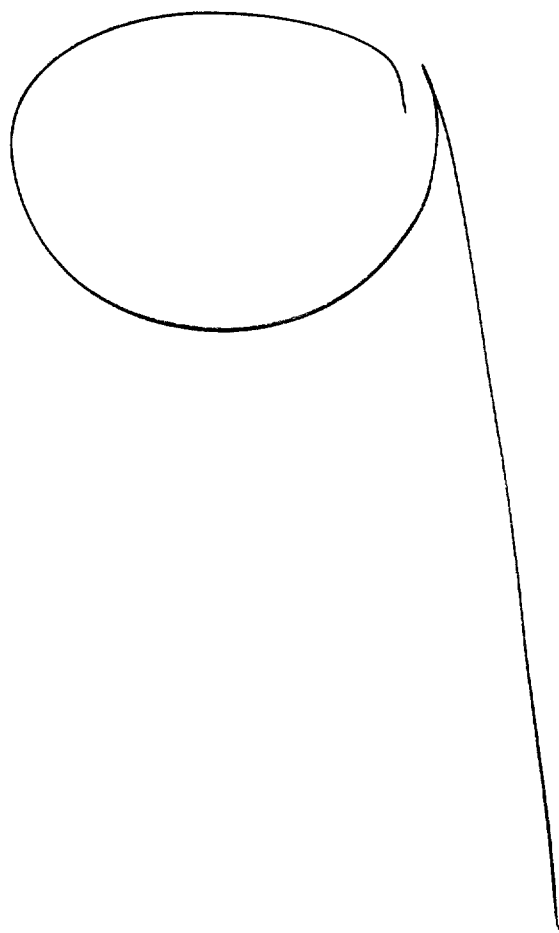
Bob Aebi
Signature

Bob Aebi
Name of Person (type or print)

6-25-00
Date
Regulation Coordinator
Title

Telephone Number 580-395-6294
Area Code Number

Please mail **completed** Form T-4c to Railroad Commission of Texas, Gas Services Division / Pipeline Safety, P. O. Box 12967, Austin, TX 78711-2967. If you have questions call (512) 463-7194.



**RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION
PIPELINE SAFETY SECTION**

RECEIVED
R.R.C. OF TEXAS
JUN 16 2000

Form T-4C
(4/97)

PIPELINE AND GATHERING SYSTEM FORM OF CERTIFICATION

Company/Address KOCH PIPELINE COMPANY, L.P. P.O. BOX 29 MEDFORD OK 73759		Permit No. 01700	P-5 No. 473732																								
<p align="center">PIPELINE CLASSIFICATION</p> <p>Common Carrier <input checked="" type="checkbox"/> Interstate <input checked="" type="checkbox"/> Gas Utility <input type="checkbox"/> Intrastate <input type="checkbox"/> Private <input type="checkbox"/> Issuance Date of Last Permit <u>6-3-99</u> Location of Line(s) by County(s) <u>Carson, Gray, Hemphill</u> <u>Potter, Roberts, Wheeler, Lipscomb,</u> <u>Moore, Ochiltree Counties</u></p>		<p align="center">PLEASE ANSWER (A) & (B)</p> <table border="0"> <thead> <tr> <th></th> <th>(A) Fluid Transported</th> <th>(B) Miles of Pipe</th> </tr> </thead> <tbody> <tr> <td>Crude</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Condensate</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Gas *</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Products *</td> <td><input checked="" type="checkbox"/></td> <td>285. ✓</td> </tr> <tr> <td>Full Oil Well Stream</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Full Gas Well Stream</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> <tr> <td>Other *</td> <td><input type="checkbox"/></td> <td>_____</td> </tr> </tbody> </table> <p>*Specify _____ Does fluid contain H₂S? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No If yes, at what concentration? _____ ppm</p>			(A) Fluid Transported	(B) Miles of Pipe	Crude	<input type="checkbox"/>	_____	Condensate	<input type="checkbox"/>	_____	Gas *	<input type="checkbox"/>	_____	Products *	<input checked="" type="checkbox"/>	285. ✓	Full Oil Well Stream	<input type="checkbox"/>	_____	Full Gas Well Stream	<input type="checkbox"/>	_____	Other *	<input type="checkbox"/>	_____
	(A) Fluid Transported	(B) Miles of Pipe																									
Crude	<input type="checkbox"/>	_____																									
Condensate	<input type="checkbox"/>	_____																									
Gas *	<input type="checkbox"/>	_____																									
Products *	<input checked="" type="checkbox"/>	285. ✓																									
Full Oil Well Stream	<input type="checkbox"/>	_____																									
Full Gas Well Stream	<input type="checkbox"/>	_____																									
Other *	<input type="checkbox"/>	_____																									

This will certify that the installations described above have not been subject to any modifications, extensions or abandonments since the issuance date of last permit.

REMARKS: _____

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

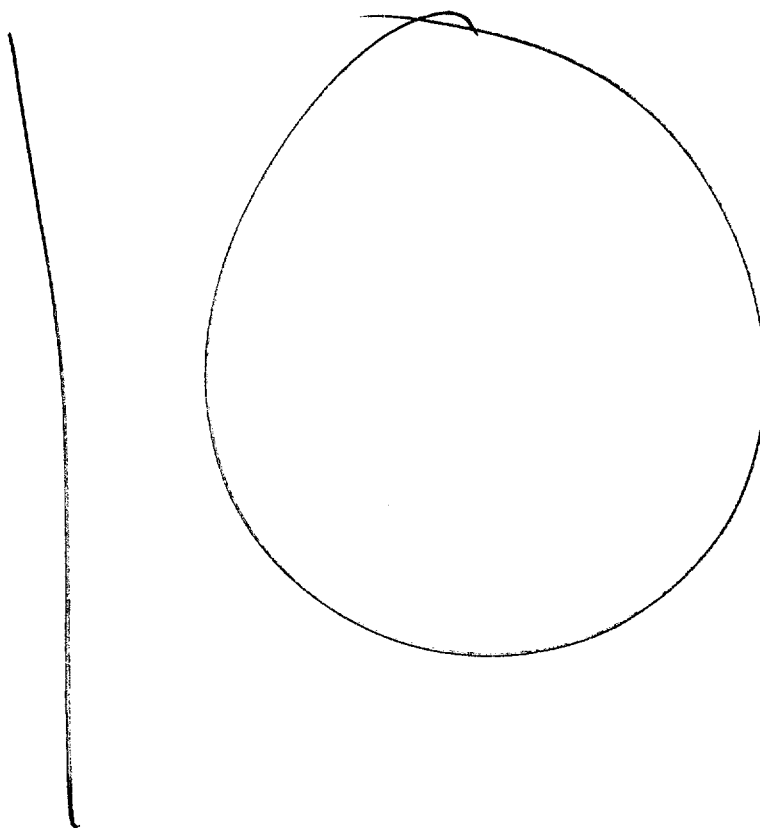
Bob Aebi
Signature

Bob Aebi
Name of Person (type or print)

5-25-00 Regulations Coordinator
Date Title

Telephone Number 580 395-6294
Area Code Number

Please mail **completed** Form T-4c to Railroad Commission of Texas, Gas Services Division / Pipeline Safety, P. O. Box 129 Austin, TX 78711-2967. If you have questions call (512) 463-7194.



RAILROAD COMMISSION OF TEXAS
GAS SERVICES DIVISION
PIPELINE SAFETY SECTION

PERMIT TO OPERATE PIPELINE

Austin, Texas, September 13, 2000

KOCH GATEWAY PIPELINE COMPANY
ATTN MICHAEL ROWZEE
P O BOX 2256
WICHITA KS 67201

Permit No. 00761
FLUID TRANSPORTED
Crude: Crude FWS:
Condensate: Gas FWS:
Gas XXX
Products
Other

This is to certify that KOCH GATEWAY PIPELINE COMPANY has complied with 16 TAC Sec. 3.65 of the Commission Rules and Regulations governing pipelines in accordance with the Natural Resources Code Sec. 81.051 and is granted this permit by the Commission to operate the following line or lines located at:

ANDERSON	ANGELINA	BEE	CHAMBERS
CHEROKEE	COLORADO	DALLAS	DE WITT
DUVAL	FORT BEND	GOLIAD	GREGG
HARDIN	HARRIS	HARRISON	HENDERSON
HIDALGO	HOUSTON	JACKSON	JASPER

** Counties continued on page 2

PERMIT AMENDED TO REFLECT THE RETURN OF 8" AND 12" LINES IN NUECES AND SAN PATRICIO COUNTIES LEASED TO CCNG GAS GATHERING, L.P., T-4 #05176. THESE LINES ARE NOW LEASED TO IBC PETROLEUM, INC. T-4 #05991.

This permit is valid until the operating ownership of such line or system changes, or until extensions or other physical changes are made in the line or system. (See Instructions on Form T-4.)

RAILROAD COMMISSION OF TEXAS

BY Kathy Arnold

KOCH GATEWAY PIPE LINE COMPANY

Permit 1 00761 Page 2

JEFFERSON
LAVACA
NEWTON
POLK
SAN AUGUSTINE
SMITH
UPSHUR
WALLER

JIM WELLS
LIVE OAK
NUECES
REFUGIO
SAN JACINTO
TARRANT
VAN ZANDT
WHARTON

KARNES
MONTGOMERY
ORANGE
RUSK
SAN PATRICIO
TRINITY
VICTORIA
WOOD

KAUFMAN
NACOGDOCHES
PANOLA
SABINE
SHELBY
TYLER
WALKER

11

4. "Attached in an Appendix to Plaintiff's Response to the Koch Defendants' Motion to Dismiss are true and correct copies of the following documents published on and printed from the Internet:

- a. Koch News titled *Entergy-Koch Approved, Open for Business Today*, published at www.kochind.com;
- b. Gulf South Pipeline Company, L.P. Operations Organizational Chart and Gulf South Operations Job Descriptions, published at www.gulfsouthpl.com;
- c. Entergy-Koch Corporate Executives, published at www.entergykoch.com;
- d. Entergy-Koch Presentation by Kyle Vann, President and CEO, at the American Gas Association, Financial Forum, May 7, 2001, published at www.entergy.com;
- e. Koch Philosophy, published at www.kochind.com; and
- f. Koch Philosophy titled *How to Succeed in Interesting Times*, by Charles G. Koch, Chairman and CEO of Koch Industries, Inc., published at www.kochind.com."

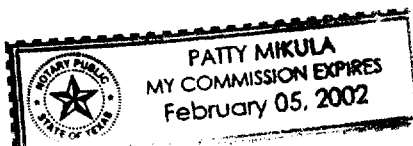
FURTHER AFFIANT SAYETH NOT.

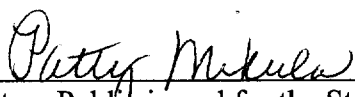


Amy Harris

STATE OF TEXAS §
 §
COUNTY OF DALLAS §

SUBSCRIBED AND SWORN TO before me by the said Amy Harris on the 26th day of September, 2001.





Notary Public in and for the State of Texas

My Commission Expires:

2/05/02

Koch News Resource **About Koch** **Koch in the Community** **Koch and the Environment** **Koch Careers**



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Koch Industries
Koch News

Date: 2/1/01

Entergy-Koch Approved, Open for Business Today

Subsidiaries Axia Energy, Axia Energy Europe, Gulf South Pipeline set to begin operations

Houston – Entergy-Koch, LP, a new wholesale energy trading, transportation and marketing company here, has earned final regulatory approval and opens for business today.

EKLP, a privately held company formed by subsidiaries of Entergy Corporation (NYSE: ETR) and Koch Industries, Inc. delivers, markets and trades power, natural gas and other energy-related commodities, including weather derivatives, through wholly owned subsidiaries Axia Energy, LP, Axia Energy Europe Ltd, and Gulf South Pipeline Company, LP.

With EKLP's startup, trading subsidiary Axia Energy ranks among the nation's top ten energy commodity traders, in terms of combined volumes of electricity and natural gas traded. It will trade volumes in excess of 100 million megawatt hours of electricity annually and 5 billion cubic feet of gas daily and provide customers a broad range of commodity sources and options, including gas, emissions, power, weather derivatives and additional risk management tools.

EKLP has assets of about \$1 billion, including the approximately 9,000-mile Gulf South interstate pipeline network (previously called Koch Gateway Pipeline), one of the largest natural gas transmission systems in the region, and the Bisteneau gas storage facility. These assets, as well as the marketing and trading capabilities of what was previously known as Koch Energy Trading, Inc., were contributed to the new company by Koch Industries. Entergy Corp. contributed its power marketing and trading businesses – which consisted of Entergy Power Marketing Corp. in the United States, and Entergy Trading and Marketing Ltd in Europe – as well as a cash investment.

"We're excited to begin serving this marketplace," said Kyle Vann, EKLP's president and chief executive officer. "We'll provide dependable, cost-effective gas transportation and supply, and we'll offer energy customers throughout North America and Europe a variety of services to run their businesses and mitigate risk as the gas and power markets evolve through deregulation. The complementary assets contributed to EKLP by Entergy and Koch – in natural gas and in the marketing and trading of power and other energy commodities – have given us the assets and the scale to compete and grow."

Vann highlighted key attributes which were contributed to EKLP from its parent companies, including a leading position in energy commodities markets and the highly disciplined commodity trading controls, procedures and systems contributed by Koch, as well as the capabilities in domestic and international power marketing and trading received from Entergy. Vann also said EKLP will market power and provide risk management and trading services for Entergy's existing and future merchant plants.

Vann expects the expanded scope and resources of the new venture to create additional growth opportunities for weather derivatives -- financial instruments designed to enable utilities and other businesses to hedge their risks of cost or sales volume fluctuations associated with temperature changes. Axia Energy, from its outset, is a market leader in that area, accounting for about 25 percent of such trades.

EKLP, which has an A credit rating from Standard and Poor and an A3 rating from Moody's

Investors Service, has received all necessary regulatory approvals to form EKLP. Plans for EKLP – which is the first venture between Koch, one of the nation's most successful energy traders, and Entergy, the third-largest U.S. generator of electric power and the nation's largest natural gas-fired generating fleet – were initially announced in April, 2000.

An eight-member board of directors governs EKLP. Entergy Corp.'s board chairman, Robert v.d. Luft, is chairman of the new company's board. Other EKLP board members include Wayne Leonard, Entergy's CEO; Don Hintz, Entergy's president; John Wilder, Entergy's CFO; Charles Koch, Koch Industries' chairman and CEO, Joe Moeller, Koch Industries' president and COO, Sam Soliman, Koch Industries' CFO, and Cy Nobles, senior vice president for Koch Industries.

Background on Entergy-Koch, LP Members

Entergy Corporation owns, manages or invests in power plants generating more than 30,000 megawatts of electricity domestically and internationally and delivers electricity to about 2.5 million customers in portions of Arkansas, Louisiana, Mississippi and Texas. Entergy, with about 12,000 employees, is a major global energy company engaged in power production and distribution operations. The Entergy futures contract on the New York Mercantile Exchange (NYMEX) is one of the largest electricity trading points in the nation. Entergy's Web site can be found at www.entergy.com.

Koch Industries, Inc. and its subsidiary companies employ 11,500 people worldwide and are involved in virtually all phases of the oil and gas industry, as well as in chemicals, plastics, energy services, chemical and environmental technology products, asphalt products, metals and mineral services, ranching, financial services, and ventures. More information on Koch is available at www.kochind.com.

-- 30--

Editors' Note: Correspondents wanting additional information on Entergy-Koch, LP are invited to join a news media teleconference at 1 p.m. CST today. Participants should dial 1-888-847-6595. The password for the call is "Entergy-Koch." CEO Kyle Vann, and CFO Dennis Albrecht will be available to answer questions about the new company during this conference call.

The following constitutes a "Safe Harbor" statement under the Private Securities Litigation Reform Act of 1995: Investors are cautioned that forward-looking statements contained in the foregoing release with respect to the revenues, earnings, performance, strategies, prospects and other aspects of the business of Entergy Corporation may involve risks and uncertainties. A number of factors could cause actual results or outcomes to differ materially from those indicated by such forward-looking statements. These factors include, but are not limited to, risks and uncertainties relating to: the effects of weather, the performance of generating units and transmission systems, the possession of nuclear materials, fuel prices and availability, the effects of regulatory decisions and changes in law, litigation, capital spending requirements, the onset of competition, advances in technology, changes in accounting standards, corporate restructuring and changes in capital structure, movements in the markets for electricity and other energy-related commodities, changes in interest rates and in financial and foreign currency markets generally, changes in corporate strategies, and other factors.

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comments@kochind.com

12

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

**P.D. HAMILTON, Individually and as
Trustee of the Prentice Dell Hamilton and
Florine Hamilton Family Trust**

VS.

CIVIL ACTION NO. 9:01CV132

**KOCH INDUSTRIES, INC., Individually
and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
GS PIPELINE COMPANY, L.L.C.,
ENTERGY-KOCH, L.P., and
EKLP, L.L.C.**

AFFIDAVIT OF R. MICHAEL McCAULEY

STATE OF TEXAS §
COUNTY OF DALLAS §

Before me, the undersigned authority, on this day personally appeared R. Michael McCauley, who being by me duly sworn, deposed and said:

1. "My name is R. Michael McCauley. I am over 21 years of age, have never been convicted of a felony, and am competent to make this affidavit. I have personal knowledge of the facts stated herein, and they are true and correct.

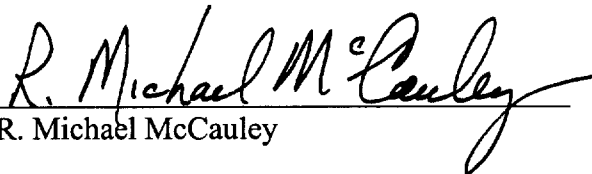
2. "I am an attorney licensed to practice law in the State of Texas and an owner of the law firm of McCauley, Macdonald & Devin, P.C. I am a member in good standing with the State Bar of Texas.

3. "I am an attorney of record for Plaintiff P.D. Hamilton, individually and as Trustee of the Prentice Dell Hamilton and Florine Hamilton Family Trust ("Hamilton"). Pursuant to Local Rule CV-11, I have also been designated as the Attorney-in-Charge for Hamilton.

4. "Attached in an Appendix to Plaintiff's Response to the Koch Defendants' Motion to Dismiss are true and correct copies of the following exhibits offered and admitted into evidence during the jury trial in the case styled *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas: Plaintiff's Trial Exhibits Nos. 27, 31, 38, 43, 50, 118 and 119, and a true and correct copy of Defendants' Trial Exhibit No. 10, and a true and correct copy of Exhibit No. 30 to the Deposition of Danny Mills.

5. "Also attached in the Appendix to Plaintiff's Response to the Koch Defendants' Motion to Dismiss are true and correct copies of portions of the deposition testimony of Kenoth E. Whitstine, Phillip Dubose, and Bill Caffey, and true and correct copies of portions of the trial testimony of Edward R. Ziegler, P.E., C.S.P., James Craddock, Charles Powell, P.E., James Tucker, Don Carson, David Kilian, Charles Misak, Roger Floyd, and Bill Caffey."

FURTHER AFFIANT SAYETH NOT.


R. Michael McCauley

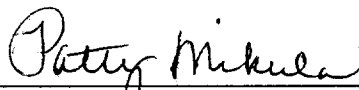
STATE OF TEXAS §
 §
COUNTY OF DALLAS §

26th SUBSCRIBED AND SWORN TO before me by the said R. Michael McCauley on the
day of September, 2001.



My Commission Expires:

2/05/02


Notary Public in and for the State of Texas



RECONSTRUCT STERLING I PIPELINE

cc: Elmore
PFI
Bull

PROJECT DESCRIPTION

The proposed reconstruction of Sterling I consists of laying 170 miles of 10" pipeline from Corsicana to Cleveland, with bi-directional capacity of 35 MB/D transporting primarily butanes and natural gasoline. Upon completion, Koch will have two pipelines batching gas liquids from Conway to the Gulf Coast with combined capacity of 125 MB/D. Capital investment is \$26.2MM plus \$1.5MM in working capital.

C-K
D-
PFI
J-

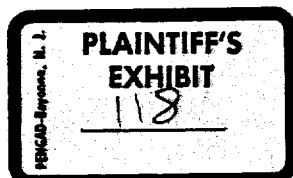
BACKGROUND

The Sterling I section of pipe between Corsicana and Cleveland, built in 1929, was retired from service in 1993 following the startup of the 12" Sterling II pipeline. Sterling II was built to transport E-P mix and propane from Medford, Oklahoma to Diamond Shamrock storage at Mt. Belvieu, Texas, with capacity of 92 MB/D. Today, Sterling II is operated as a batch line delivering E-P mix, propane, isobutane, normal butane and natural gasoline to Warren Petroleum and Diamond Shamrock at Mt. Belvieu, with capacity of 90 MB/D. Current throughput is 85 MB/D.

SUMMARY

The volume of gas liquids delivered from the Midwest to the Gulf Coast for petrochemical feedstocks is expected to increase by at least 50 MB/D by 1998 from the following sources: expansion in Oklahoma, increased production from the Hugoton field in Kansas, existing customers on our system, and upside volume from Canada. In Oklahoma, Texaco-Maysville could deliver 6 MB/D of raw feed into Koch's gathering system, and gas plant expansion and consolidation with more efficient plants in Oklahoma by Transok-Commanche and others is already taking place. New production of at least 30 MB/D from the Hugoton with increased ethane recovery is expected, with plants already planned by Amoco, Mobil and CIG. Existing customers, including Conoco in 1996 and Western in 1997, will likely want Mt. Belvieu delivery options, already part of transportation & fractionation agreements with Centana, Transok and Torkawa, when their current contracts are renegotiated. In addition, gas liquids production of at least 50 MB/D from western Canada is anticipated to be available at Conway via a new pipeline within five years. Owning two pipelines making deliveries to the Gulf Coast will greatly enhance Koch's competitive advantage for delivering specification products to the Gulf Coast by increasing our capacity and flexibility to perform this service. The bi-directional flow capability of Sterling I will also allow Koch to respond quickly to the market and capture opportunity for additional profits on both gas liquids and refined products when the Gulf Coast-Midwest spreads invert. Constructing Sterling I pipeline in 1997 generates a DCF ROIC of 17.3% with an after-tax NPV at 8% of \$10,634M, as shown on the attached economic summary.

}
*



KFVB 07E000

An opportunity exists to reconstruct Sterling I pipeline now instead of waiting for the increased volumes, estimated to be three years. Building now creates three sources of savings: Medford storage investment, Diamond Shamrock fees, and power savings. Underground storage for purity products at Medford will be taken out of service due to operational constraints, requiring above-ground storage to be constructed at Medford to meet both the operational requirements for the fractionator and the batching requirements for deliveries to Conway and the Gulf Coast. The reconstruction of Sterling I pipeline reduces the capital investment for above-ground storage at Medford by \$10MM and provides additional capacity and flexibility for batching products to the Gulf Coast. Additionally, Sterling I provides the necessary delivery capacity and flexibility to allow the Medford fractionator to be expanded from today's capacity of 180 MB/D to 210 MB/D in the future. An additional investment in storage at Medford over and above the \$10MM would be required to provide the same performance capability to expand the fractionator.

Second, savings are derived from Diamond Shamrock, who will reduce fees charged to Koch in the amount of \$600M/yr for five years. In order to improve their competitive advantage, Diamond Shamrock has committed to develop additional storage at Mt. Belvieu to provide the capability to receive batches of all products from Sterling II at rates up to 96 MB/D. Because the lower Sterling I delivery rates of 35 MB/D for butanes and natural gasoline will save Diamond Shamrock significant investment, they have agreed to pass a portion of these savings on to Koch.

Third, Sterling I will generate power savings of \$500M/yr in years 1-3 based on current volumes south, compared to Sterling II alone.

The savings afforded to Koch by building Sterling I today increases Koch's net present value by nearly \$5 million, as shown on the attached economic summary, compared to building above-ground storage today at Medford.

RECOMMENDATION

Approval is requested to reconstruct Sterling I pipeline for \$26.2MM and for additional investment of \$1.5MM in working capital, for a total approved investment of \$27.7MM.

*• Smaller Batches
• Storage when North
Keeps pl from being dented*

*• Covered the standards
• Integrity of roofs
out of skirt coming out of casing
800' - 1000'
100' 5
Hered 5T*

*No high rates during winter
EP in North of 4*

RECONSTRUCT STERLING I PIPELINE ECONOMIC SUMMARY

PROPOSAL: Reconstruct Sterling I P/L now instead of waiting 3 years.

<u>INVESTMENT:</u>	<u>\$MM</u>
R.O.W., 14-yr str ln	\$5.44
Pipeline, 15-yr 150%	<u>\$20.76</u>
	\$26.20

PROJECT BASIS:

Underground storage at Madford is taken out of service at time zero.

Sterling I P/L is put back in service to the Gulf Coast at time zero.

Diamond Shamrock does not build storage, Koch saves \$600M/yr in fees yrs 1-5.

Sterling I power savings of \$500M/yr in years 1-3 (current volumes south).

Volumes to the Gulf Coast increase by 25,000 B/D in year 4.

Revenue - 2.50 cpg, Opcast - 22 cpb.

15-year project life, no decline.

Assets written off at project end, recover working capital.

Effective tax rate - 38%; Ad valorem tax - 1.5%.

ECONOMIC ANALYSIS:

	<u>Timing</u>	<u>84Tax Value</u>	<u>After-Tax NPV at 8%, \$M</u>		
			<u>Build \$1 Now</u>	<u>Wait 3 Yrs.</u>	<u>Diff.</u>
Madford storage savings:	yr 0	\$10MM	7,712	0	7,712
Power savings:	yrs 1-3	\$0.5MM/yr	830	0	830
Diamond Shamrock:	yrs 1-5	\$600M/yr	1,544	0	1,544
Capital cost:	yrs 1-3	\$26.2MM	(22,112)	(17,464)	(4,648)
Working capital cost:	yrs 1-3	\$1.5MM	(1,027)	(718)	(309)
S,G&A Cost:	yrs 1-3	\$100M/yr	(551)	(385)	(166)
Oper. Income on 25,000 B/D:	yrs 4-15	\$7.6MM/yr	<u>29,201</u>	<u>29,201</u>	<u>0</u>
			Total:	15,597	10,634
					4,963
			DCF ROR:	17.7%	17.3%

RLK 9/29/94

KP\B 072002

KOCH INDUSTRIES, INC. Mont Belvieu Delivery System

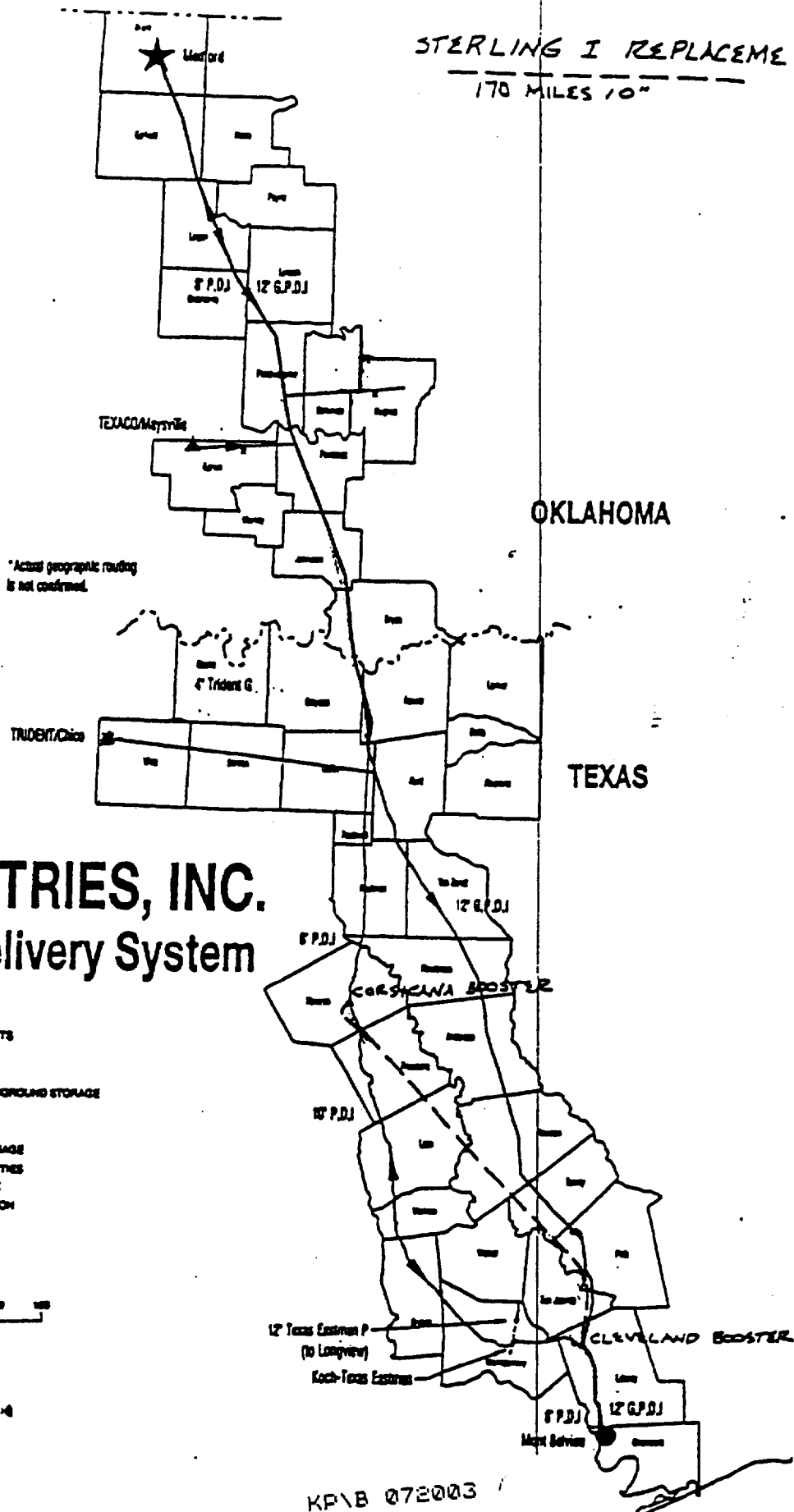
- LEGEND**
- ★ MISCELL FLOOD PROJECTS
 - ★ FRACTIONATORS
 - ▲ GAS PLANTS
 - △ GAS PLANTS WITH UNDERGROUND STORAGE
 - PETROCHEMICAL PLANTS
 - REFINERIES
 - TERMINALS, DOCKS, STORAGE
 - ▨ TRUCK UNLOADING FACILITIES
 - UNDERGROUND STORAGE
 - PIPELINE INTERCONNECTION



STERLING I

STERLING II

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13

1 NO. 51458
2 DANNY SMALLEY, * IN THE DISTRICT COURT
INDIVIDUALLY AND AS *
3 INDEPENDENT ADMINISTRATOR *
OF DANIELLE DAWN SMALLEY, *
4 DECEASED, JUDY SMALLEY, *
KENNETH STONE, *
5 INDIVIDUALLY AND AS *
PERSONAL REPRESENTATIVE *
6 OF THE ESTATE OF *
JASON KENNETH STONE *
7 *
VS. * KAUFMAN COUNTY, TEXAS
8 *
KOCH INDUSTRIES, INC., *
9 KOCH PIPELINE COMPANY, *
L.P., KOCH HYDROCARBON *
10 COMPANY, KPL/GP, INC., *
AND RONALD GANT * 86TH JUDICIAL DISTRICT
11 *****
12

VIDEOTAPED ORAL DEPOSITION OF

KENOTH EDWARD WHITSTINE

July 1, 1999

Volume 1 of 1

19 ORAL VIDEOTAPED DEPOSITION of KENOTH EDWARD
20 WHITSTINE, produced as a witness at the instance of
the plaintiffs, and duly sworn, was taken in the
21 above-styled and numbered cause on the 1st day of
July, 1999, from 10:15 a.m. to 6:26 p.m., before
22 B. Irene Meguess, RPR, Texas CSR No. 2429, reported by
machine shorthand, at the Offices of Nell McCallum &
23 Associates, Inc., 2615 Calder, Suite 111, Beaumont,
Texas, pursuant to the Texas Rules of Civil Procedure
24 and the provisions stated on the record.
25

NMA

2

1 A P P E A R A N C E S

2 For the Plaintiffs:

3 R. MICHAEL McCAULEY

4 McCauley, MacDonald, Devin & Huddleston, P.C.

5 3800 Renaissance Tower

6 1201 Elm Street

7 Dallas, Texas 75270

8 -and-

9 MARQUETTE WOLF

10 Ted B. Lyon & Associates, P.C.

11 18601 LBJ Freeway, Suite 525

12 Town East Tower

13 Mesquite, Texas 75150

14 For the Defendants:

15 SEAN P. BRENNAN

16 Fulbright & Jaworski, L.L.P.

17 2200 Ross Avenue, Suite 2800

18 Dallas, Texas 75201

19 The Videographer:

20 BRIAN BOBBITT

21 In Attendance:

22 TANNIS M. STONE

23 Legal Assistant

24 McCauley, MacDonald, Devin & Huddleston, P.C.

25 3800 Renaissance Tower

26 1201 Elm Street

27 Dallas, Texas 75270

* * * * *

4
1 (DEPOSITION EXHIBIT WHITSTINE NO. 1
2 WAS MARKED)
3 THE REPORTER: This is being taken
4 pursuant to notice and subpoena; correct?
5 MR. McCAULEY: It is.
6 THE REPORTER: Stipulations?
7 MR. McCAULEY: Under the Rules.
8 THE REPORTER: Are all parties
9 represented here?
10 MR. BRENNAN: Yes.
11 THE REPORTER: What about signature?
12 MR. McCAULEY: We'd like him to read it
13 and sign it.
14 THE REPORTER: Directly to him?
15 MR. BRENNAN: Yes.
16 MR. McCAULEY: After she does this,
17 it's going to be typed up and it's going to end up
18 being in a little booklet form and she's going to send
19 it to you to read. If there are any mistakes in it --
20 for example, if you said "yes" and it got put down as
21 "no" -- she wouldn't do that, of course -- but if it
22 had some mistake -- if you said 6th and it was
23 supposed to be 5th or something -- you'd just have a
24 place where you can make that correction in the
25 back --

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5
1 THE WITNESS: Okay.
2 MR. McCAULEY: -- and then sign it and
3 you'll send it back to her and she'll send it to us.
4 THE WITNESS: Okay.
5 THE VIDEOGRAPHER: Today's date is
6 July 1st, 1999. The time is 10:17 a.m. We're on the
7 record.
8 KENOTH EDWARD WHITSTINE,
9 having been first duly sworn, testified as follows:
10 EXAMINATION
11 BY MR. McCAULEY:
12 Q. State your full name, please.
13 A. Kenoth Edward Whitstine.
14 Q. Mr. Whitstine, my name is Mike McCauley; and
15 you and I have met before today; isn't that true?
16 A. Yes, sir.
17 Q. You understand that you're here today to be
18 deposed in a lawsuit wherein I and Mr. Wolf, sitting
19 here with me, represent the plaintiffs and the
20 defendants are various Koch Industry Company or
21 affiliates related to your former employer. Do you
22 understand that?
23 A. Yeah, basically I guess.
24 Q. Okay. And you came today because of a
25 subpoena that was sent to you, and I've got a copy

10

1 several different job classifications. In 19- --

2 Q. Before you start breaking those down, just
3 generally you worked in what industry -- what
4 industry?

5 A. Oh, natural gas pipeline industry.

6 Q. Okay. So that the jury will understand,
7 we'll narrow it down a little bit.

8 A. Yes, sir.

9 Q. So, you started out, you worked in the
10 natural gas pipeline industry for a total of how many
11 years before -- well, let me ask you: Are you still
12 in that industry?

13 A. No, sir.

14 Q. Have you retired from that industry?

15 A. Basically, yeah.

16 Q. How many years were you in that industry
17 before you retired?

18 A. 31 1/2, roughly.

19 Q. Okay. You just told us that for 29 1/2 of
20 that you were with United Gas Pipeline; is that
21 right?

22 A. Yes, sir.

23 Q. And then, for the other two years, who were
24 you with?

25 A. Koch Gateway Pipeline.

11

1 Q. All right. How did -- how did it come about
2 that you left -- you were no longer with United and
3 became employed by Koch?

4 A. Koch purchased United Gas Pipeline in 1993
5 or somewhere right in there.

6 Q. All right. And I'll appreciate, as we go
7 along here today, if you'll give your best
8 recollection of dates like that. I know you may not
9 be exactly right because it's hard to remember when
10 everything exactly happened. But it will help the
11 jury and it will help us if you'll help us get a time
12 frame that way.

13 So, in approximately 1993 you became an
14 employee of Koch by virtue of an acquisition they made
15 of United Gas; is that correct?

16 A. Correct.

17 Q. All right. Now, I apologize for sort of
18 interrupting you awhile ago. Let me take you back to
19 where you were.

20 Tell the jury, if you would, what your work
21 background was at United over those 29 1/2 years, just
22 sort of the general categories of your
23 responsibilities and your promotions.

24 A. Basically I started off in the compressor
25 department and then the pipeline and worked in

12

1 measurement and communications, worked some in the gas
2 control -- worked in all the different areas of our --
3 every facet of operations that United Gas Pipeline
4 had.

5 Up until 1973 -- I had transferred several
6 locations prior to that, about 11 times, I believe.
7 And I was made supervisor at the Amaudville compressor
8 station, which had turbine engines.

9 Q. Where is that?

10 A. In Amaudville, Louisiana.

11 Q. Louisiana. Okay.

12 A. I had worked there for -- as a supervisor
13 for approximately two years after that and was
14 promoted to a compressor superintendent at a brand-new
15 compressor station in Vinton, Louisiana. And I was
16 there until about 1990, '91.

17 And then I went into Houston under a -- they
18 pulled five people out of the field to come into
19 Houston for a reorganization. And I was one of the
20 individuals pulled out of the field to have a field
21 input to the reorganization of the company.

22 Q. Approximately what year was that?

23 A. I believe that was in 1991.

24 Q. Okay. So -- just so I'm clear, between '73
25 and '91, you were a field supervisor in some capacity,

13

1 at some location; is that correct?

2 A. Yes, sir.

3 Q. And in '91 you say they brought you and some
4 other selected persons in to the -- I guess it's the
5 home office or the company's office --

6 A. Yes, sir, the home office in Houston.

7 Q. -- to participate in a -- some project
8 associated with the reorganization, which I'll ask you
9 more about later; but generally is that correct?

10 A. Yes, sir; yes, sir.

11 Q. And how long were you involved in that
12 project?

13 A. Approximately six months.

14 Q. Okay. And then what did you do?

15 A. Then I was given another job back in
16 Westlake, Louisiana, with an increase in
17 responsibilities; and I was an area manager then, over
18 all the measurement and communication and corrosion in
19 the Westlake area.

20 Q. When you say "area manager," is that higher
21 than a supervisor; or is that a --

22 A. Yes, sir. When we reorganized, we basically
23 put a manager over more stuff and then had some
24 smaller supervisors underneath us to -- well, in fact,
25 we did away with all the other supervisors, to tell

14

1 you the truth.

2 Q. All right. So, as an area manager, did you
3 have larger area -- larger responsibility, greater
4 responsibility than you had previously, before '91 as
5 a supervisor?

6 A. Sure; yes, sir.

7 Q. Okay. I'll come back to that in a minute,
8 and we'll talk about that.

9 Then, did you stay in that position as an
10 area manager up until the time of the acquisition by
11 Koch?

12 A. Yes, sir.

13 Q. Then, when Koch acquired the company, did
14 your job title or your job duties change?

15 A. Yes, sir. I was -- I transferred to
16 Goodrich, Texas; and I was over the Goodrich area.

17 Q. Where is Goodrich, please?

18 A. Goodrich is kind of north of Houston on 59,
19 about 65 miles north of Houston.

20 Q. Okay. I'm sorry. Go ahead. So, what did
21 you do at Goodrich?

22 A. I was basically over the Goodrich area,
23 which started at Needville, Texas, about 40 miles
24 south of Houston, through -- that would be the south
25 boundary. The west boundary would be the

15

1 Huntsville-Conroe area. The north boundary would be
2 the Lufkin-Nacogdoches area. And the east boundary
3 would have been the Louisiana state line.

4 And I was over every facet of our operations
5 in that area under Koch Gateway Pipeline.

6 Q. Okay. So, you were -- what was your title?
7 Was it still area manager or different?

8 A. They -- I'll tell you the truth: They
9 changed the -- the name of it from -- and I hate to
10 say this, but I -- it was not long before I left, they
11 changed it to something else.

12 Q. Okay. When you say you were over every
13 facet of the operation, you mean all aspects of the
14 operation within that geographical area of -- of
15 the -- of that particular Koch line you were
16 responsible for?

17 A. Yes, sir. All pipelines, measurement,
18 communications, corrosion, everything.

19 Q. All right. So, then you had somebody under
20 you who would work -- for example, you didn't do
21 everything. You had somebody under you --

22 A. Yes, sir.

23 Q. -- that would be a corrosion specialist or
24 somebody who might be a --

25 A. Correct.

16

1 Q. -- various kinds of expertise, cathodic
2 protection --

3 A. When I first arrived in Goodrich, there were
4 31 personnel slots. And not very long after -- just a
5 matter of days after I was there, we -- that number
6 was lowered.

7 Q. You mean some people were let go?

8 A. Yes, sir.

9 MR. BRENNAN: Objection, nonresponsive.

10 Q. (By Mr. McCauley) All right. Now, during
11 the course of the deposition, one of the lawyers may
12 make an objection like that, and that's to preserve it
13 on the record. And what he's really saying is he's
14 going to tell the Judge he didn't think the answer
15 responded to my question, but that's all right. That
16 doesn't affect your answer.

17 A. Oh, okay.

18 Q. So, go ahead and answer.

19 A. If I say something wrong, tell me.

20 Q. No, we'll give you a chance to clear it up.

21 MR. WOLF: He's going to --

22 MR. McCAULEY: Then he won't have any
23 objections.

24 Q. (By Mr. McCauley) You stayed in the,
25 Goodrich area how long?

17

1 A. I was there until October of '94.

2 Q. Did you actually live up in that area?

3 A. Yes, sir.

4 Q. Okay. And what happened in October of '94?
5 Was that the end of your employment with Koch?

6 A. Yes, sir.

7 Q. Okay. So, you stayed in the Goodrich area
8 up until the end of your employment period?

9 A. Correct.

10 Q. With the same job?

11 A. Yes, sir.

12 Q. All right. If I could -- I appreciate that
13 overview of your -- of your -- how many years'
14 experience? When did you start -- what year did you
15 start with United Gas?

16 A. July the 1st, 1963.

17 Q. Almost a year -- almost to the day, isn't
18 it? Today is -- what is this, the 1st, isn't it?

19 MR. WOLF: Uh-huh.

20 Q. (By Mr. McCauley) It is July the 1st.

21 A. It was the 1st or the 10th. I may be wrong
22 there.

23 Q. So, from '63 to '94, 31 years -- a little
24 over 31 years, you were in that industry; and I would
25 like to go back and start with the period when you

42

1 in any way, if it was at all, when you were with Koch?

2 MR. BRENNAN: Objection, form.

3 A. The main difference was that with United
4 we -- we knew at least a year ahead of time where and
5 how many beds we needed to work on. And with -- and
6 we budgeted money in the following year's budget to do
7 this.

8 With Koch, Koch didn't have a budget --
9 well, not that I worked with. I worked with budgets
10 for years and years, but I didn't work on them with
11 Koch.

12 They just said that when something needs to
13 be done, there is money there to fix it and that you
14 don't budget money ahead of time. But as far as the
15 time frame, as far as the anodes are considered, it
16 wouldn't have changed any.

17 Q. (By Mr. McCauley) Was it your experience,
18 one way or the other -- did you have any experience
19 while you were with Koch, after the acquisition, as to
20 whether or not Koch did follow that policy of, "There
21 was money there, we'll just fix it when it needs to be
22 fixed"?

23 A. Some things -- if it was an emergency, sure,
24 there was no problem.

25 Q. In other words, if you had a hole in the

43

1 line, is that an emergency?

2 MR. BRENNAN: Objection, leading.

3 A. Yeah. If we had a bad leak or something,
4 you know, we fixed it.

5 Q. (By Mr. McCauley) What about routine kind
6 of things that you know are scheduled, did those get
7 the same level of attention that they did at United?

8 A. Well, they got the same level of attention
9 in my area, from me, but not -- they didn't -- well, I
10 don't know how to say -- I didn't always get to do
11 what I wanted to do because of priorities.

12 Q. Well, did you -- after the acquisition by
13 Koch of the pipelines, when you were -- while you were
14 in the Goodrich area, did you ever have a situation
15 where you saw a need for something that you felt
16 required attention and you were unable to get the
17 attention that you felt was required?

18 A. Yes, sir, on several different items.

19 Q. All right. Would you start with -- I guess
20 the best way -- I'll ask you to take what you think
21 was the most serious or the most pressing and just
22 describe that to the jury. What was the situation?

23 A. Most of the ones that I was in deep concern
24 over was exposed pipe out in the middle of the wild
25 blue yonder.

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1 Q. When you say "exposed pipe," tell the jury
2 what that means.

3 A. That means pipe that no longer has any
4 ground -- earth cover over it, that it sticks out
5 above the ground.

6 Q. Okay. Why -- well, strike that.

7 So, there were some instances where you had
8 exposed pipe and you were concerned about it; is that
9 what you're saying?

10 A. Yes, sir.

11 Q. Why is that a concern? What concern does
12 that raise?

13 A. Mainly for -- in the areas that -- where
14 these particular ones were, I was afraid that -- these
15 were real old pipelines -- and I'm saying "old" --
16 laid in the 1920s and I don't know exact dates on it
17 but somewhere in the '20s.

18 Q. Uh-huh.

19 A. In fact, it was Mobil gas at that time.

20 They had -- the pipelines weren't welded,
21 they were Dresser coupling, and I don't know if I need
22 to explain what a Dresser coupling is.

23 Q. I'll come back and ask you later. So, they
24 were not welded; but they were coupled. All right.
25 Go ahead.

45

1 A. And when this old pipe that hadn't had
2 cathodic protection on it for a number of years, when
3 it was laid, but later on in the '50s, when that
4 became a good science and cathodic protection was put
5 on there, these were the lines that had all the leaks
6 in them. These were the ones that had real bad
7 corrosion and stuff on them. But we slowed it way,
8 way down by the using the cathodic protection.

9 Q. Okay. Now, you had some pipes. You just
10 described their condition. Why are you concerned if
11 they're above ground, is my question? What difference
12 does it make if they're exposed or not?

13 A. Well, where -- where our right-of-ways are,
14 usually it's 50 foot wide. And we keep it -- or kept
15 it maintained in case there was any type of emergency
16 or whatever on the pipeline, that we could get our
17 vehicles, our repair equipment down there to make the
18 repairs. And also, through just the luck of where the
19 pipelines run, the landowners themselves also use our
20 right-of-ways as roads. And a good portion of the
21 area that I was concerned about was through Temple --
22 I'm not sure if it's Temple Timber Company or
23 Temple -- I'm not sure exactly what the name of the
24 company is. All these companies change their names so
25 much. But it was originally with Temple, and they had

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1 pine trees growing out there and they had logging
2 trucks that go out there all the time.
3 And this was on the 16-inch that went from
4 Magasco down to Call-Junction, is the location that --
5 is what we called it. And that's where our pipeline
6 ended. From there it was owned by another company who
7 had abandoned it years before.

8 Q. Okay. Going back to the question, though:
9 What was your concern about this pipeline sticking
10 up? What risk was it; why did you care?

11 A. I was afraid that a logging truck or any
12 type of equipment might hit it and punch a hole in it.

13 Q. What would happen if that occurred?

14 A. More than likely you'd have a blow-out and a
15 big fire.

16 Q. All right. Now, so, that's an example where
17 you had a situation where you saw a need as a manager
18 to take some action; is that correct?

19 A. Well, there's for sure that; but also --
20 well, it wasn't in compliance. So, I needed to --

21 Q. All right. What did you do --

22 MR. BRENNAN: Objection, nonresponsive.

23 Q. (By Mr. McCauley) All right. Let me ask
24 you: In your opinion, at that point in time, was the
25 condition of the pipeline in compliance with

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1 regulatory requirements?

2 A. No, sir.

3 Q. All right. What did you do, if anything, to
4 try to get some action to deal with that situation?

5 A. I reported it to Mr. McMullen, oh, back in
6 '93, some of the locations. And as I was there
7 longer, I found more and more different spots on
8 different pipelines that were basically the same type
9 of a situation. But I reported it to him. And then,
10 I got -- he told me to get an estimate on -- from a
11 contractor, three different bids on what it would take
12 to put the pipeline back in compliance or repair it;
13 and I did that several different times. I can't
14 remember exactly how many times. But it was on two or
15 three different occasions I had outside contract
16 people come and go out to the location and look at it
17 and then give me a bid on what it would take to fix
18 it.

19 And as time grew, like I said, other ones
20 came up and I would report them. On the line from
21 Huntsville to -- oh, gosh, I'm trying to think --
22 Crockett, there is an old -- I believe it was a 6 inch
23 that had been in there for umpteen hundred years,
24 too. And it had the same conditions.

25 Through the years, erosion from rain or one

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1 thing and other, the earth had eventually washed away
2 from the pipeline. Some of them we had were in the
3 creek bottoms. The pipeline would just be hanging out
4 across the creek, instead of underneath the creek,
5 where it was originally.

6 And -- but the creeks bothered me somewhat.
7 But most all this stuff was -- some of it was out in
8 the middle of nowhere, which didn't need immediate --
9 or I -- I attempted to get the most immediate places
10 repaired first.

11 Q. Let me come back -- let me ask you --

12 MR. BRENNAN: Objection, nonresponsive.

13 Q. (By Mr. McCauley) Let me come back to the
14 immediate places, 'cause that's what I was trying -- I
15 need to get you to focus a little more specifically
16 for the jury's benefit here.

17 Let's take -- let's take -- as I said, I
18 want you to take an example of one that was immediate
19 and tell the jury what you did about it.

20 A. Well, first off, I took pictures of -- this
21 was in either late '93 or early '94. I took pictures
22 and wrote up a memo on 12 to 15 different locations
23 that needed -- in my opinion, needed immediate
24 attention. And I sent this to Mr. McMullen; and I
25 also sent a copy to Steve Hendrix at the Magasco area,

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1 who was over a good portion of it, as a -- kind of
2 a -- not as -- well, he was kind of a supervisor but
3 not quite. Leadman, I think, is what they called
4 him. And also I kept a record of this at the Goodrich
5 office.

6 And I sent that in to Mr. McMullen to let
7 him physically see what I was talking about, because I
8 wasn't getting much response on my bids. I was just
9 told to get more bids and word my needs a little bit
10 different, that -- my explanations for wanting to get
11 the money to do these different jobs. I spent more
12 time doing that than anything else.

13 MR. BRENNAN: Objection, nonresponsive.

14 Q. (By Mr. McCauley) Were these lines required
15 to be covered pursuant to the easement agreements, to
16 your knowledge?

17 A. Oh, yes, sir; yes, sir.

18 Q. How do you know that?

19 A. Well, on one section of it, the one that
20 went through Temple, Steve Hendrix had got wind of --
21 from some Temple employees that Temple was fixing to
22 turn us in to DOT. And so, I sent off to Wichita
23 'cause we didn't have a right-of-way department in
24 Houston anymore and asked an individual up there that
25 I knew if he could get me a copy of the right-of-way

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1 agreement on the section of line that we was talking
2 about.
3 And it took him awhile to dig it out, but he
4 found it and he sent me a copy of it. And I sent a
5 copy to Mr. McMullen. And I believe I sent a copy to
6 Steve Hendrix, so that he would have it on his
7 records.

8 Q. What were the requirements --

9 MR. BRENNAN: Objection, nonresponsive.

10 Q. (By Mr. McCauley) What were the
11 requirements that you learned from that document, as
12 far as covering of the pipeline?

13 A. Of course, this document was written back in
14 the '20s; but it -- basically it said that -- that we
15 would maintain the right-of-way and maintain a minimum
16 of 18 inches of cover over all the pipeline. And
17 18 inches of cover means that if you've got a piece of
18 ground laying out there and -- you should be able to
19 get a probe and hunt for the pipeline. You should
20 have at least 18 inches of dirt on top of the
21 pipeline.

22 Q. All right. And did that Temple pipeline
23 generally have 18 inches of cover over it?

24 MR. BRENNAN: Objection to form.

25 A. In some places it would, but --

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1 were all over basically two different pipelines or
2 maybe three pipelines, but different places on that
3 pipeline. In other words --

4 Q. (By Mr. McCauley) Okay. I understand.

5 A. They would be a couple of miles apart
6 maybe.

7 Q. All right. So, if you had 15 submitted
8 memos or paragraphs, they dealt with different
9 geographical locations; is that correct?

10 MR. BRENNAN: Objection, form;
11 objection, leading.

12 A. Yes, sir.

13 Q. (By Mr. McCauley) Did you ever get
14 permission to take any kind of remedial action with
15 regard to any of those 15 locations?

16 A. No, sir.

17 Q. Did you ever have a conversation, one or
18 more conversations, with Mr. McMullen, where you sat
19 down and talked with him about that?

20 A. Yes, sir. I can't remember the exact date
21 at all, but it was in the early part of '94. I
22 finally got Mr. Ed to -- that's what we used to call
23 him -- not -- not in a funny -- not like the horse I
24 mean; that's just what we'd call him -- to come out to
25 the location on the Huntsville line to -- for him to

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1 Q. (By Mr. McCauley) Did it have areas that
2 didn't have?

3 MR. BRENNAN: Objection, leading.

4 A. There was a lot of areas that didn't have
5 any. I mean it was sticking out of the ground 4 or
6 5 inches.

7 Q. (By Mr. McCauley) So, you sent a memo and
8 photographs and then later a copy of this right-of-way
9 agreement that you obtained from Wichita to your
10 direct supervisor; is that correct?

11 A. Yes, sir.

12 Q. And that -- from what you described, was it
13 just one memo or was it several memos?

14 A. Well, it was, best of my recollection, three
15 pages of -- I had written a pretty good-sized
16 paragraph on each individual concern that I had and
17 seems like there was 15 or more different ones. I
18 just don't remember for sure right now.

19 Q. Okay.

20 MR. BRENNAN: Objection, nonresponsive.

21 Q. (By Mr. McCauley) Would each one of those
22 be a different location; is that what you mean when
23 you say "different ones"?

24 MR. BRENNAN: Objection, leading.

25 A. Each one of my concerns would be -- they

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1 physically look at them, because I was very concerned
2 about it and I wanted to make sure he understood why I
3 was so concerned about it.

4 And he met me out there this particular
5 day. And I showed him two or three different spots on
6 that pipeline, where the pipeline was exposed. And I
7 showed him that it was in an area where -- one of the
8 areas they were -- somebody had been cleaning off this
9 side of this hill with a blade of some -- I guess a
10 grader blade or a bulldozer.

11 You've got to remember that on these --

12 Q. Before you get sidetracked, let me tell
13 you --

14 MR. BRENNAN: Objection, nonresponsive.

15 Q. (By Mr. McCauley) -- what happens is -- I'm
16 just going to tell you -- what happens is when you
17 answer these questions, it is helpful when you go off
18 to these explanations; but --

19 A. I'm sorry.

20 Q. -- if you'll wait and let us ask you for the
21 explanations, then it will make it cleaner for the
22 record.

23 A. Okay. I apologize.

24 MR. McCauley: So, your objection, I
25 think, was going to be what he was about to do. I

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1 don't know if it was for what he had already done. I
2 think he had just been answering up to that point.
3 But do you want -- I can ask him the question over,
4 but I think you were anticipating what he was about to
5 do.

6 What do you want to do?

7 MR. BRENNAN: I made my objection.

8 Q. (By Mr. McCauley) All right. Then let me
9 come back and ask you --

10 MR. McCAULEY: Read the question --
11 read back the question I asked that he started
12 answering.

13 (THE REQUESTED MATERIAL WAS READ BACK)

14 Q. (By Mr. McCauley) Okay. About your -- when
15 I say "about that," I'm referring to the memos that
16 you submitted, the 15 separate memos, on the issues
17 that they were based on.

18 A. Okay. Well, that -- that's when I had him
19 meet me out there at this particular location.

20 Q. Okay. So, you did have a conversation with
21 him; and you had it out in the field. Is that
22 correct?

23 MR. BRENNAN: Objection, leading.

24 A. Yes.

25 MR. McCAULEY: All right. If you want

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1 to do this every time, I can make this a five-day
2 deposition.

3 Q. (By Mr. McCauley) Where did you have the
4 conversation with him?

5 A. At the particular location of my concerns.

6 Q. Okay.

7 A. Of some of the concerns.

8 Q. All right. Which was the Temple location;
9 is that correct?

10 A. No, sir, this wasn't the Temple location.
11 This was on the Huntsville line.

12 Q. All right.

13 A. Which was really minor compared to the ones
14 on the Temple line.

15 MR. BRENNAN: Objection, nonresponsive.

16 Q. (By Mr. McCauley) If you can and to the
17 best you can, tell me when this was.

18 MR. WOLF: Wait a minute. Sean, I
19 understand your need to object when it is merited; but
20 some of those -- the rules do say "like you're in
21 trial." And when I try a case, I've never see a
22 lawyer object -- and I understand you've got to do it
23 sometimes, but come on.

24 When he says "over here in this field,"
25 that might not be exactly responsive; but in trial,

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1 you're not going to pull that. Can you just temper it
2 just a little bit?

3 MR. McCAULEY: Otherwise, we're going
4 to be here a long time; and I don't think the Judge is
5 going to like this.

6 MR. WOLF: I know -- I know what you're
7 saying and I understand when you need to make them,
8 but not -- I mean but not always. Come on.

9 MR. McCAULEY: When he says "and I ate
10 my lunch at the same time," you don't have to object
11 every time.

12 MR. BRENNAN: I understand when I'm
13 supposed to object and when I'm not. So --

14 MR. WOLF: I know you do.

15 Q. (By Mr. McCauley) Now, if you would relate
16 the conversation you had with Mr. McMullen -- strike
17 that.

18 Give us, if you would, the closest time
19 frame that you can, if possible, to when that meeting
20 took place.

21 A. This meeting took place, best of my memory,
22 sometime in the first or middle part of April of 1994.

23 Q. Okay. And relate the communication that you
24 had with him and the exchange you had, the best you
25 can recall it.

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1 A. I talked with him and I told him that -- you
2 know, "Here it is, this is what I'm worried about."
3 And he said that he understood my concerns and that I
4 needed to understand that sometimes economically
5 people are -- we should do things in a certain fashion
6 or a certain priority and that was -- that money spent
7 on particular things on pipelines that don't make very
8 much money, sometimes is not financially advisable, I
9 guess, or economical because it takes forever, if
10 ever, that that money would ever be recouped from the
11 expenditure that you made and that sometimes you
12 needed just to take that into consideration when
13 you're wanting to spend money on particular things.

14 And then, I asked him that -- I said: Well,
15 you know -- I said: You know, one of them logging
16 trucks could drive over this line here and it could
17 very possibly drag the Dresser off or something and
18 cause a blow-out and possibly burn, catch on fire, and
19 kill the -- whoever might be in the logging truck.

20 And he said that he understood that and --
21 but that I needed to understand that money spent on
22 certain projects could make a lot more money than on
23 other projects and that they could come back and pay
24 off a lawsuit from an incident and still be money
25 ahead.

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1 I don't know if I said that right or not,
2 but it's --

3 Q. Was that the way he told it to you? That's
4 my question.

5 A. Basically the way I understood it was
6 that -- that if -- if I didn't spend money doing a
7 particular job -- not that particular one we may be
8 looking at, I'm not sure -- but a particular job, that
9 I could take that same money that -- say it was going
10 to cost ten or twenty thousand dollars to repair that
11 particular location or maybe even more than that,
12 depending on the location -- but some of them were as
13 minor as ten to fifteen thousand dollars -- that that
14 money could be invested elsewhere and that money would
15 multiply greatly. And it's -- it was better to take a
16 gamble of something happening later and handle that
17 situation when it arose.

18 Q. So, did he actually say to you that if there
19 were a lawsuit arising from an incident like you
20 described to him of somebody getting killed or burned
21 that it would be better to pay that than to fix the
22 pipeline in some instances?

23 MR. BRENNAN: Objection, leading.

24 A. Yes, sir, he said that.

25 Q. (By Mr. McCauley) You had known him for

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1 some years, hadn't you?

2 A. Yes, sir.

3 Q. Was that -- the philosophy that you just
4 described, had that been the United philosophy
5 regarding maintenance and operational expenses?

6 A. Absolutely not.

7 Q. Can you contrast for the jury any difference
8 that you perceived then between the philosophy you had
9 experienced in working under United and that which you
10 were now working under at Koch with regard to those
11 kinds of expenditures?

12 A. Under United Gas, the best of my
13 recollection, or the best of what I was aware of
14 anyway, we -- we might have postponed doing something
15 for a very short period of time, until maybe some
16 money could be gathered up to get it done; but I
17 was -- I was never asked to slide on safety at all --
18 never. United Gas just would not -- they wouldn't
19 operate thataway.

20 Q. As an almost 20-year supervisor with United,
21 had you ever seen a comparable situation where United
22 failed to fix and repair a condition similar to or in
23 the same nature or the same risk category to people or
24 property as existed in this Temple Huntsville area you
25 described?

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1 A. No, sir. The -- the only difference I could
2 say would be with United possibly it might have been
3 postponed for a certain length of time and that would
4 not be very long but that was just to gather money or
5 get money appropriated to do the jobs, where Koch had
6 the money right there to take care of it all the time,
7 is what they'd always told us.

8 You know, that -- with United it might have
9 been a financial burden to perform such jobs; but they
10 would still try to do it or still do it. And that
11 would be the only difference.

12 MR. BRENNAN: Objection, nonresponsive.

13 Q. (By Mr. McCauley) Did you say anything back
14 to Mr. McMullen when he said that about the -- paying
15 the lawsuit?

16 A. I was in shock, to tell you the truth. I
17 just couldn't hardly believe what I had heard. And he
18 was my boss; and I said, "Okay."

19 And then, when I got home that night, I
20 talked it over with my wife. And that's when I
21 decided that I was going to resign.

22 Q. I want to go ahead and skip ahead to that
23 for just a second. Did you -- and then we'll come
24 back.

25 Did you, in fact, resign from Koch; or under

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1 what circumstances did you leave?

2 A. No, sir, I didn't resign. I had -- I was
3 fixing to resign.

4 Q. Okay. Let's go to that time period. In
5 April, after this meeting, you had this conversation
6 with your wife. What happened next in terms of
7 your -- process leading to your ultimate separation
8 from Koch or termination with Koch, just relating to
9 your employment?

10 A. Well, by that time I had -- later on that
11 year, I think it was in the early part of the summer,
12 that's when Bob O'Hare transferred in from Wichita and
13 become my supervisor --

14 Q. Uh-huh.

15 A. -- immediate supervisor and which I was told
16 I could still talk with Mr. Ed also. But I had to --
17 most everything I went through Bob O'Hare with after
18 that. And Bob O'Hare and I didn't always agree on
19 everything.

20 And approximately -- I believe it was 10 or
21 12 days before I left Koch, Bob O'Hare had called me
22 in to the office in Carthage for an evaluation that
23 was due. And I got over there about 11:30 that
24 morning, and he was fixing to go to lunch. But beings
25 as I was already there, he said we could go ahead and

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1 my conscience.

2 MR. BRENNAN: Objection, nonresponsive.

3 Q. (By Mr. McCauley) Now, how much before you
4 left Koch was that conversation with Mr. McMullen
5 about -- well, not the conversation but the result of
6 the conversation where you got the \$8,000 bid and
7 submitted it back to him -- how long was that before
8 you left Koch?

9 A. Oh, several months probably.

10 Q. Have you ever heard of market-based
11 management?

12 A. Oh, yeah.

13 Q. Tell the jury what your understanding was of
14 market-based management.

15 A. Well, basically, from my understanding
16 anyway, it worked with how you spent money. And
17 basically, when you spent money, whatever you spent
18 that money on should be a profit-maker and -- or
19 contribute to a profit-maker and that that money spent
20 should come back and pay for itself within six months
21 and make Koch more money after that, that -- Koch
22 believed that any investment they made should bring
23 back at least a minimum of -- it was either 30 or
24 33 percent profit.

25 And it -- it also included in personnel. It

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1 included everything involved in my operation because
2 when we were coming up with salaries for our people
3 that was looked at in the same respect, as it should
4 have been, I guess.

5 What could you have hired somebody locally
6 to do that job? If you're paying somebody \$12 an
7 hour, could you get it done for six?

8 And some jobs you could. But a lot of jobs
9 that that individual might have been doing, you
10 couldn't. So --

11 Q. Where did you learn about market-based
12 management?

13 A. After I went to Koch.

14 Q. And how did you learn about it?

15 A. Went to Wichita and through -- we had -- I
16 don't know -- a several-day seminar thing up there.
17 And then, also had -- brought a lot of stuff back.

18 We were given stuff beforehand, also, to
19 read over and -- so we would be, I guess, smart enough
20 to ask questions once we got up there, when they were
21 going through it.

22 Q. Did you get that little book that's got
23 Charles Koch's forward in it, about market-based
24 management?

25 A. Oh, I'm sure we did, yeah. We saw a lot of

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1 videos and stuff from Mr. Koch.

2 Q. While you were up there in training, he was
3 in some of the videos?

4 A. Yes, sir. And sometimes they'd send the
5 videos out in the field to play to the employees.

6 Q. So, you'd get -- you would get videos sent
7 out for the employees to look at about how
8 market-based management worked or what the philosophy
9 was?

10 A. Yeah. Because they -- it really needed to
11 drift all the way down to each individual.

12 Q. And you're saying Mr. Koch was in --
13 Mr. Charles Koch was in some of those videos?

14 A. He was in videos and I can't swear if it was
15 pertaining to market-based management itself, but it
16 was where Koch was and what they intended to be and
17 this and that and the other. I'm not positive about
18 the videos on market-based management. Seems like he
19 would be the chief guy on that.

20 MR. BRENNAN: Objection, nonresponsive.

21 Q. (By Mr. McCauley) How -- based on your
22 experience as a manager under Koch for almost two
23 years, how did market-based management play in the
24 decision-making process regarding operations, -
25 expenditures, maintenance, and those kinds of things,

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1 if it did at all?

2 A. How did it affect my decision?

3 Q. Not your decisions. How did it play in the
4 company's policies in terms of what you observed on
5 how operations were carried out, how maintenance was
6 carried out, and those kinds of things?

7 MR. BRENNAN: Objection to form.

8 A. From my experience, we did very little
9 preventive maintenance. Basically it was the
10 philosophy that if -- you know, "If it ain't broke,
11 don't work on it."

12 I would -- had been brought up under another
13 philosophy of keeping stuff in good shape so it don't
14 break and leave you stranded.

15 Q. (By Mr. McCauley) Did you attribute that
16 little preventative maintenance in some way to
17 market-based management?

18 A. Yeah, because that didn't -- you had to
19 quantify a lot of stuff, and there wasn't ways you
20 could put numbers on certain things.

21 Q. So, if you couldn't put it -- you're saying
22 you had to put it into the formulation or the concept
23 of market-based management in order to get it
24 approved; is that what you mean?

25 A. Basically, yeah.

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1 Q. And you referred earlier to something about
2 if you couldn't recover your investment within -- what
3 did you say, how many days?

4 A. Six -- I think it was six months.

5 Q. Six months. Then was that -- was that one
6 of the concepts that you learned under market-based
7 management, that concept of having to recover your
8 investment?

9 A. Yes, sir.

10 Q. When you were at United, what was the United
11 management policy with regard to preventive
12 maintenance?

13 A. We had an intensive preventive maintenance
14 schedule. We had -- in fact, that's what it was
15 called, "preventive maintenance schedule," on almost
16 everything. And basically it was -- if we could
17 foresee something coming down the line that was going
18 to be needing attention, it was basically -- part of
19 it was so we could budget money sometime during the
20 year to get this done. And that was one reason why we
21 had to keep an eye on it so close, so we could budget
22 the money for it 'cause it -- if it wasn't in the
23 budget, then it was a lot harder to get.

24 With Koch it was -- you didn't have a
25 budget. So, they always just told me to wait until it

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1 breaks and then they'll fix it.

2 Q. Whoever -- who told you that? Who gave you
3 that direction?

4 A. I -- I guess Mr. McMullen and Bob O'Hare or
5 whoever. It was --

6 Q. People over you?

7 A. Yes, sir.

8 Q. Now, did you -- I want to go back to those
9 pipes out there that were exposed in the Temple and
10 Huntsville area and your meeting with Mr. McMullen
11 where you actually physically showed them to him after
12 giving him the pictures and the reports.

13 A. Now -- well --

14 Q. Did -- after your meeting with him out there
15 where he made that statement to you you described
16 earlier about paying the lawsuits, was anything done
17 following that meeting, while you were still at Koch,
18 to address the problem of that exposed pipe that you
19 described?

20 A. Not while I was there.

21 Q. And how much --

22 A. I was told later that they had done
23 something about some of them.

24 Q. All right. How much longer were you there
25 from the time of that meeting with Mr. McMullen until

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1 your last day? How many months passed?

2 A. That was in -- I believe that was in April.

3 Q. And you left in October?

4 A. Yes, sir.

5 Q. During the intervening period between April
6 and October, did you again at any time ever have any
7 discussion with Mr. O'Hare or Mr. McMullen about the
8 problem of those exposed pipes out there? Did you
9 continue to talk to them about it, in other words?

10 A. Correct. Well, in that -- one of the later
11 meetings with Mr. O'Hare, it came up because Temple,
12 like I said earlier, had told Steve Hendrix that they
13 were fixing to turn us in. And --

14 Q. You mean to DOT?

15 A. Yes, sir.

16 Q. Okay. Go ahead.

17 A. And if -- in my background with United Gas
18 Pipeline, boy, you did not want your name turned in to
19 DOT for nothing. I mean, you know, that's just
20 unheard of.

21 But Mr. O'Hare wasn't that concerned about
22 it. He said that they couldn't -- his comment was
23 that they couldn't do that or something to that
24 effect, that they had no legal rights or they couldn't
25 tell us how to maintain our right-of-way.

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1 And I just told him at that time that I
2 thought that basically anybody, if they saw something
3 that didn't look right, anybody could call and turn
4 somebody in. I didn't think you had to have any kind
5 of rights at all. But I didn't know that for a fact.

6 Q. Other than that --

7 MR. BRENNAN: Objection, nonresponsive.

8 Q. (By Mr. McCauley) Other than that
9 conversation with Mr. O'Hare, where the subject of
10 repairing or bringing up to proper standards that
11 exposed pipe, did you have any others with
12 Mr. McMullen or Mr. O'Hare that you can remember
13 between April and October?

14 A. Well, that one with O'Hare still. This was
15 during that evaluation I was talking about. He said
16 that I needed to either learn or understand one, that
17 it's -- let me see if I can phrase this right -- that
18 it's a lot more efficient to possibly not do some
19 things and save that money and invest it elsewhere,
20 where it will grow, and take a chance on getting
21 caught sometime down the line and paying some kind of
22 fine, which usually didn't amount to very much, and
23 that -- that they had a stable full of lawyers at
24 Wichita that handled those situations.

25 MR. BRENNAN: Objection, nonresponsive.

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1 A. That was where I did the old draw the sword
 2 in the sand thing and said, I'm not going no more.
 3 Q. You threw in the towel?
 4 A. Basically.
 5 MR. BRENNAN: No further questions.
 6 THE VIDEOGRAPHER: The time is 6:26.
 7 We're off the record.
 8 (PROCEEDINGS CONCLUDED AT 6:26)

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1 I, KENOTH EDWARD WHITSTINE, have read the
 2 foregoing deposition and hereby affix my signature
 3 that same is true and correct, except as noted on a
 4 separate page and signed by me.
 5
 6
 7
 8 KENOTH EDWARD WHITSTINE
 9
 10 THE STATE OF _____ *
 11 COUNTY OF _____ *
 12 Before me, _____, on this day
 13 personally appeared KENOTH EDWARD WHITSTINE, known to
 14 me or proved to me under oath or through
 15 _____ to be the person whose name is
 16 subscribed to the foregoing instrument and
 17 acknowledged to me that they executed the same for the
 18 purposes and consideration therein expressed.
 19 Given under my hand and seal of office this ____
 20 day of _____, A.D., 1999.
 21
 22
 23
 24 NOTARY PUBLIC IN AND FOR
 25 THE STATE OF _____

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1 ERRATA SHEET
 2 DEPOSITION OF: KENOTH EDWARD WHITSTINE, JULY 1, 1999
 3 PAGE LINE CHANGE REASON
 4 _____
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 22 _____
 23 _____
 24 _____
 25 Signature: _____ Date: _____

349

1 NO. 51458
 2 DANNY SMALLEY, * IN THE DISTRICT COURT
 3 INDIVIDUALLY AND AS *
 4 INDEPENDENT ADMINISTRATOR *
 5 OF DANIELLE DAWN SMALLEY, *
 6 DECEASED, JUDY SMALLEY, *
 7 KENNETH STONE, *
 8 INDIVIDUALLY AND AS *
 9 PERSONAL REPRESENTATIVE *
 10 OF THE ESTATE OF *
 11 JASON KENNETH STONE *
 12 VS. * KAUFMAN COUNTY, TEXAS
 13 KOCH INDUSTRIES, INC., *
 14 KOCH PIPELINE COMPANY, *
 15 L.P., KOCH HYDROCARBON *
 16 COMPANY, KPL/GP, INC., *
 17 AND RONALD GANT * 86TH JUDICIAL DISTRICT
 18 *****
 19 REPORTER'S CERTIFICATION
 20 DEPOSITION OF KENOTH EDWARD WHITSTINE
 21 JULY 1, 1999
 22 I, B. IRENE MEGUESS, RPR, Certified Shorthand
 23 Reporter No. 2429 in and for the State of Texas,
 24 hereby certify to the following:
 25 That the witness, KENOTH EDWARD WHITSTINE, was
 26 duly sworn by me and that the transcript of the oral
 27 deposition is a true record of the testimony given by
 28 the witness;

350

1 That the deposition transcript was submitted on
2 _____, 1999, to the witness, for
3 examination, signature, and return to the offices of
4 Nell McCallum & Associates, Inc., by _____,
5 1999;

6
7 That the amount of time used by each party at the
8 deposition is as follows:

9
10 R. Michael McCauley 2 hours 52 minutes
11 Marquette Wolf 40 minutes
12 Sean P. Brennan 3 hours 6 minutes
13

14 That pursuant to information given to the
15 deposition officer at the time said testimony was
16 taken, the following includes all counsel for all
17 parties of record:

18
19 For the Plaintiffs:

20 R. MICHAEL McCAULEY
21 McCauley, MacDonald, Devin & Huddleston, P.C.
22 3800 Renaissance Tower
23 1201 Elm Street
24 Dallas, Texas 75270

25 -and-
MARQUETTE WOLF
Ted B. Lyon & Associates, P.C.
18601 LBJ Freeway, Suite 525
Town East Tower
Mesquite, Texas 75150

351

1 For the Defendants:
2 SEAN P. BRENNAN
3 Fulbright & Jaworski, L.L.P.
4 2200 Ross Avenue, Suite 2800
5 Dallas, Texas 75201

6 I further certify that I am neither counsel for,
7 related to, nor employed by any of the parties or
8 attorneys in the action in which this proceeding was
9 taken, and further that I am not financially or
10 otherwise interested in the outcome of the action.

11 Further certification requirements pursuant to
12 Rule 203 of TRCP will be certified to after they have
13 occurred.

14
15 Certified to by me this 13th day of July, 1999.
16
17
18
19
20

21 _____
22 B. IRENE MEGUESS, RPR, Texas CSR No. 2429
23 Expiration Date: 12-31-00
24 Nell McCallum & Associates, Inc.
25 2615 Calder, Suite 111
Beaumont, Texas 77702
409/838-0333

352

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18 COMPANY, KPL/GP, INC., *
19 AND RONALD GANT * 86TH JUDICIAL DISTRICT
20 *****

21 FURTHER CERTIFICATION UNDER RULE 203 TRCP

22 The original deposition was/was not returned to
23 the deposition officer on _____, 1999;

24 If returned, the attached Changes and Signature
25 page contains any changes and the reasons therefor;

26 If returned, the original deposition was
27 delivered to Marquette Wolf, custodial attorney;

28 That \$ _____ is the deposition officer's
29 charges to Marquette Wolf, TBA No. 00797685, for .

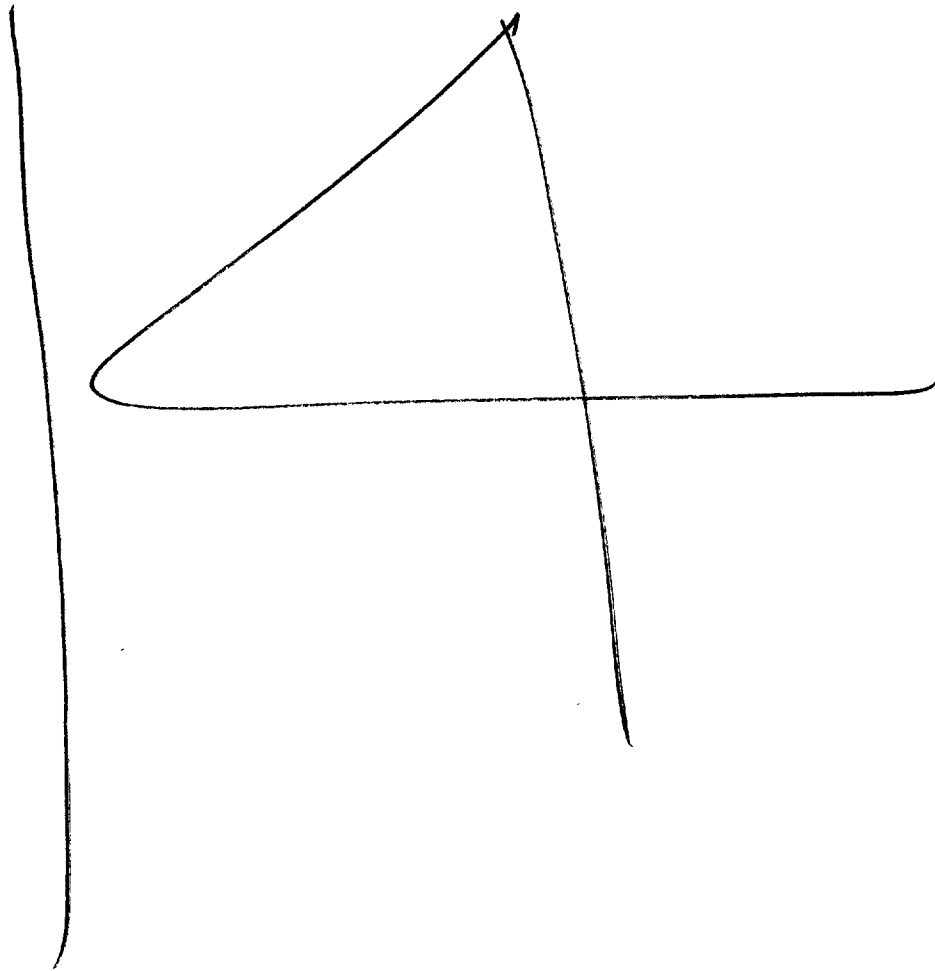
353

1 preparing the original deposition transcript and any
2 copies of exhibits;

3
4 That the deposition was delivered in accordance
5 with Rule 203.3, and that a copy of this certificate
6 was served on all parties shown here on _____,
7 1999, and filed with the Clerk.

8
9 Certified to by me this ____ day of _____,
10 1999.

11
12
13
14 B. IRENE MEGUESS, RPR, Texas CSR No. 2429
15 Expiration Date: 12-31-00
16 Nell McCallum & Associates, Inc.
17 2615 Calder, Suite 111
18 Beaumont, Texas 77702
19 409/838-0333
20
21
22
23
24
25



It was, and is, my understanding that natural gas pipelines such as those which were operated by Koch were regulated by the United States Government through the Department of Transportation ("DOT"). Department of Transportation regulations require reporting of the pipeline conditions to the DOT. DOT regulations require that written reports be submitted or maintained for DOT inspection as it relates to leaking pipelines and valve inspections. There are other required reportings, including maintenance operations and gas transmission totals.

My job duties included general pipeline maintenance and performing the required DOT inspections while working with other Koch employees to assure the integrity of the natural gas pipelines we were responsible for pursuant to DOT guidelines.

In 1996, a new supervisor, Jerry Gullette, was assigned to the Goodrich area, which included work that I performed. The first day Mr. Gullette arrived as my new supervisor in 1996, he suggested to me that DOT compliance was costing Koch profits and he definitely said we were going to avoid compliance with regulations of DOT in order to enhance the profitability of our employer. At that point in time, I told Mr. Gullette that I would not lie for him or Koch and that I would not file false reports. I knew at that point in time that it would be illegal to intentionally avoid DOT regulations in failing to report required information or in filing false documentation relating to DOT required reports. When I informed Mr. Gullette that I would not lie, he acted as though he was mad at me. Several months later in 1996, Mr. Gullette asked me to sign a number of DOT required inspection reports which contained false information. Mr. Gullette asked me to sign valve inspections which Mr. Gullette knew had not been conducted. When I refused to sign these reports, Mr. Gullette again acted as if he was angry with me. Mr. Gullette then called in a former employee, who no longer worked for any of the Koch companies, and had that former employee sign these reports. At the time Mr. Gullette knew that these were, in fact, false reports with fictitious information entered as to dates of inspection and other information. Mr. Gullette threatened to fire me for reasons that I could only associate with my refusal to falsify DOT reports. I made several attempts to communicate by phone with Greg Pearson, Mr. Gullette's supervisor, regarding these matters, but Mr. Pearson refused to discuss them with me. I also attempted to discuss these DOT requirements with Mr. Gullette, but he would always respond with anger and tell me that I did not know how to be a Koch employee. In the early months of 1997, I was again called upon by my supervisors, Dale McBride and Greg Crum, to falsify DOT reports by putting information on such reports that was fictitious or incorrect. I refused to do this and was criticized by both Mr. Crum and by Mr. McBride. During the remaining time that I was a Koch employee, it was obvious from the demeanor of my supervisors that Koch did not want its employees to comply with DOT regulations, despite written Company policy to the contrary, if by not complying Koch could make more money. I was fired by Koch because I would not engage in illegal conduct.

One of my prior supervisors, Kenoth Whitstine, told me that Koch intended to sacrifice safety for profits. There were large sections of natural gas pipeline in the area we were responsible for which were completely uncovered and exposed, and which was not reported or repaired, even though we made Koch officials aware. Mr. Whitstine seemed very disturbed by Koch's insistence that he and those that worked under his supervision such as myself were

regulations. Only after a few weeks following Mr. Whitstine's statement to me, his employment came to an end with Koch. Prior to his departure, Mr. Whitstine told me that he was ordered by his supervisors to perform no more mowing of pipeline meter stations and any employee caught with a mower in their truck might be terminated. After Mr. Whitstine left, I worked under Mr. Pearson's supervision for just over a year. Mr. Pearson was never critical of my work product and Koch only became unhappy with my work after I told Mr. Gullette I would not violate DOT regulations. I did not know what the exact statutes were, but I felt like a person could go to jail if they did some of these things or assisted others in doing these things which resulted in violation of DOT regulations, either through reporting or through silence in failing to report known safety hazards such as gas leaks and the like.

DOT compliance and the safety of the pipelines was never a vital concern of Koch Gateway. Despite the written rules and regulations, Koch by and through supervisors like Jerry Gullette, Dale McBride and Greg Pearson, made it plain that profits were the vital concern of Koch over and above everything else, including safety. If you were not interested in doing whatever it took, including avoiding DOT regulations, to enhance the profitability of Koch, then you were not a "good Koch employee". In a monthly safety meeting, Bob O'Hair, a Koch supervisor two levels above me, told me that it's cheaper to pay a fine for a DOT violation than to do the maintenance on the pipeline. My attempts to meet Federal and State regulations in regard to pipeline safety were criticized by Mr. Pearson. Mr. Pearson made it plain to me that if I did not follow Mr. Gullette's directions, obviously implying failing to comply with DOT regulations and reporting, then my job with Koch was in jeopardy. The only reason for my discharge was my refusal to commit illegal acts in conspiring with my supervisors and others to violate DOT regulations.

Mr. McBride, during his time as my supervisor, requested that I alter prior inspection reports and falsify such reports in ways to suit him. Mr. McBride had created valve inspections reports which were fictitious. Mr. McBride was unhappy with me because he and I had worked together and Mr. McBride was aware that I had knowledge that he, Mr. McBride, had on numerous occasions in the past, prepared and filed false DOT reports. Mr. McBride had consistently provided information for DOT reports that was both inaccurate and/or non-existent. Mr. McBride even created valve inspection reports for valves which no longer existed. Mr. McBride was aware that I had knowledge that Mr. Gullette, Mr. Pearson, and he, Mr. McBride, had signed off on approvals for valves which had been removed many years ago. These supervisors were so careless in their attitude toward DOT compliance that they were creating inspection reports for non-existent valves as a result of their lack of knowledge of what had happened and/or was occurring to our gas pipelines. On one occasion, I went to inspect valves that were painted two years earlier only to find that the paint was still on the grease fittings for the valves, indicating that they had not been greased for the prior two years. I had to take a pocket knife and chip off the paint in order to perform the required maintenance. Nevertheless, valve reports had been prepared to indicate that these valves had been maintained and inspected during the prior two years.

During the time that I was Koch employee, at meetings where Mr. Ed McMullen attended, he along with other supervisors would indicate to us that Koch Gateway Pipeline Company was in reality Koch Industries, Inc. He did not say this in those exact words, but there was no question as to Mr. McMullen's meaning. Mr. McMullen, Mr. Bob O'Hair, Mr. Greg Pearson, Mr. Jerry Gullette, and other Koch representatives, all referred to our employer as being Koch. I was led to believe by Mr McMullen and other supervisors that Koch Industries, Inc. and Koch Gateway Pipeline were one in the same.

My former supervisor, Mr. Kenoth Whitstine, told me that Ed McMullen and Bob O'Hair told him in no uncertain terms that DOT compliance was not as important as profits. Mr. Whitstine also told me that Mr. McMullen told him never to put written criticisms regarding pipelines in any memos that were prepared regarding pipeline conditions. I was also told by Mr. Whitstine that after Koch took over these pipelines, that Koch, unlike the predecessor company, had no maintenance budget at all. It was Koch's routine, custom and habit not to spend money on maintenance unless something broke or blew up. It was obvious to me, as a 15-year veteran of pipeline maintenance, that Koch had no intention of performing appropriate maintenance on the pipelines in my area. This failure to perform appropriate maintenance translated into DOT violations. It was not irregular for Koch to backdate inspection reports due to lack of manpower to get reports done within required time frames. The need for additional manpower was brought to the attention of management, but those needs were not met. Contrary to Koch's written policies and procedures, it was a job requirement to avoid DOT regulations, either directly or indirectly, if they would require additional manpower or cash expenditures.

I drove the pipeline from Huntsville, Texas, to Crockett, Texas, on September 18, 2001, and it is obvious to me after my inspection that the pipeline is not being maintained in an appropriate manner. There were many areas where the pipeline was not adequately marked to identify the location of the pipeline. I was able to identify locations where the pipeline was buried only 14.5 inches deep crossing a public road. The general right-of-way area was overgrown, sometimes seven to eight feet tall, except in locations where private property owners were maintaining it, so that even if markers were present, they were concealed by the brush. I saw exposed pipe and at two different locations was able to smell mercaptan where gas was obviously escaping from Koch's system.

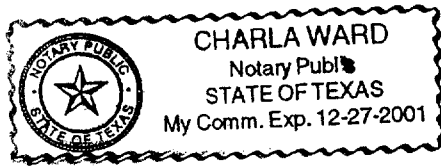
My September 18th drive of Koch's natural gas pipeline, much of which is as much as 70 years old, convinced me that Koch's lack of maintenance has become far more serious since I left Koch in 1997. These are but a small example of the right-of-way violations which I witnessed on September 18, 2001.

I have not prepared this Affidavit because I am angry over having been wrongfully discharged by Koch. After a wrongful termination lawsuit against Koch I settled with them. My concern, and thus my willingness to look at the pipeline on September 18, 2001, and to execute this Affidavit, is to help to avoid a terrible disaster that I know will occur if Koch does not change its practices.

Further Affiant sayeth not."

Bobby L Conner
Bobby Conner

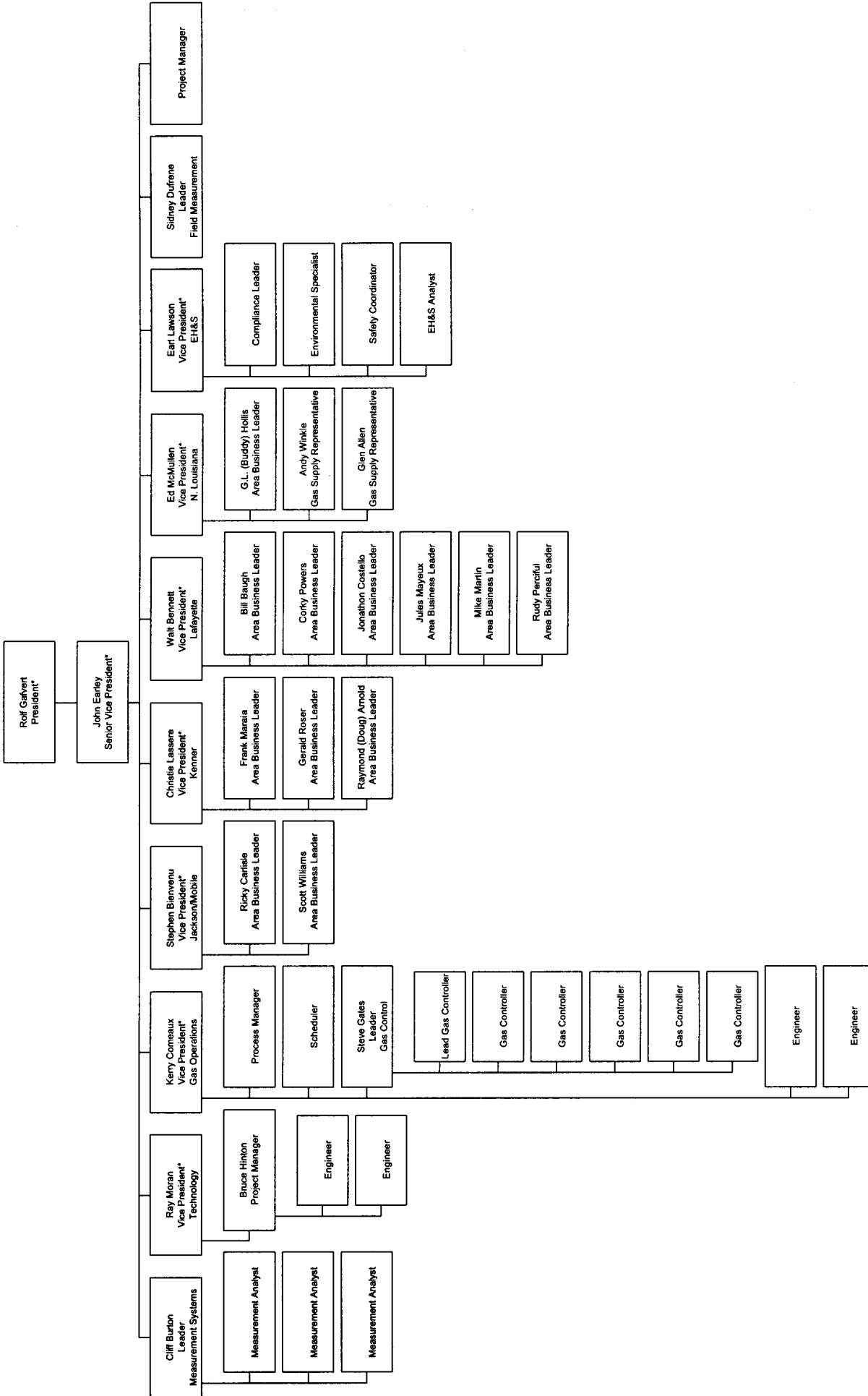
Sworn to and subscribed before me on this 19th day of September, 2001.



Charla Ward
Notary Public in and for
the State of Texas

15

Gulf South Pipeline Company, LP Operations



* An officer of GS Pipeline Company, LLC, the General Partner of Gulf South Pipeline Company, LP

Gulf South Operations Job Descriptions (03/05/01)

***Indicates employee is involved in transportation or gas sales**

***Senior Vice President**

The leader of the operation services group with ultimate responsibility for developing and implementing all business strategies related to pipeline operations. Leads efforts related to locating and connecting new wellhead supplies to pipeline system. Reports to the President of Gulf South.

***Leader, Measurement Systems**

Leader of Houston measurement services. Primary responsibilities include data acquisition, integration and reporting for all field measurement devices.

Measurement Analyst

Assist the coordination of field operations daily activities and special requests, as well as provide reports, data files and analysis for customers who require the Measurement Information Processing System (MIPS) as a resource. May also monitors all electronic flow measurement (EFM) with communications to ensure the proper handling, interpretation, and recording of data received. May also communicates with field measurement and SCADA to ensure EFM performance excellence.

Director, Technology

Oversight responsibility for the development of various capabilities which support the operation and commercial groups in Gulf South. These include Engineering, Corrosion, Communications, Compression, Reliability, System Planning, ROW, Records, SCADA and Mapping.

Leader, Reliability

Provide leadership for pipeline reliability regarding compression, corrosion, communications, and system planning capabilities. Primary responsibilities include providing technical support and oversight for pipeline operations.

***Engineer**

Responsible for initial prospect contact, pricing, deal structure, oversight of the connection, and initial gas flow.

***Vice President, Gas Operations**

Leader of the Gas Operations group which is responsible for the scheduling and dispatching of all gas volumes in a safe and efficient manner. Reviews firm transportation analysis and facility designs. Also responsible for maintaining and developing qualified personnel to accomplish these responsibilities.

Process Manager

Provides business support to the design, development, and implementation of computer systems used within the Customer Service and Operations areas. Provided leadership and guidance regarding the processes of nominations, confirmations, and scheduling.

***Scheduler**

Evaluates the system capabilities and schedules appropriate quantities on the system. Interfaces with the marketing groups to assess impacts to the system and communicate appropriately.

***Leader, Gas Control**

Manages and directs Gas Control personnel to monitor the pipeline system and dispatch volumes in a safe and efficient manner. Interfaces with the field personnel to coordinate any pipeline or compressor maintenance that would impact flows. Interacts with marketing group to assess incremental operating cost of potential deals.

***Lead Gas Controller**

Coordinates day-to-day activities of the Gas Controllers so that they monitor the pipeline system and dispatch volumes in a safe and efficient manner. Evaluates facility shutdown proposals from field personnel to determine the system impact and communicates recommended timing to field personnel.

***Gas Controller**

Monitor system pressures and flows utilizing available information in order to ensure that the volumes are dispatched in a safe and efficient manner.

***Vice President**

Oversight responsibility for all day-to-day operations, maintenance, and wellhead supply connection activity. Daily operations include all activities associated with the receipt, transportation and delivery of gas. Maintenance responsibilities include on-going system maintenance as well as management of reliability initiatives. Wellhead supply responsibility includes initial prospect contact, pricing, deal structure, oversight of the connection and initial gas flow.

***Area Business Leader**

Responsibilities include initial prospect contact, pricing, deal structure, oversight of the connection, and initial gas flow.

***Gas Supply Representative**

Responsibilities include initial prospect contact, pricing, deal structure, oversight of the connection and initial gas flow.

Leader, Field Management

Primary responsibilities include oversight for design, installation and maintenance of all field measurement devices. Additional responsibilities include personnel selection and training.

***Project Manager**

Retain and grow long-term (1 year or longer) profitable business by maintaining existing and capturing new business opportunities. Primary responsibilities include origination, analysis, negotiation and internal communication capabilities. Manages the sale and purchase of certain pipeline assets.

Vice President, Environmental Health and Safety

Lead the ongoing effort with Gulf South to systematically identify and comply with applicable environmental, health, safety and DOT requirements. Educate and gain support of business and operations leaders for environmental, health, safety and DOT compliance programs and processes. Work with business and operations leaders to integrate environmental, health, safety and DOT processes with business. Illustrate the benefits of environmental, health, safety and DOT compliance to business and operations leaders.

Compliance Leader

Work to identify and comply with applicable environmental requirements at the facility level. Work with facility personnel to integrate environmental processes into daily activities. Gain support of facility managers for environmental compliance programs and processes. Lead waste and water effort for facilities.

Environmental Specialist

Work to identify and comply with applicable environmental, health and safety requirements at the facility level. Work with facility personnel to integrate environmental, health and safety processes into daily activities. Gain support of facility managers for environmental, health and safety compliance programs and processes. Analyze air permit status of facilities and identify valuable options, recommend improvements and ensure consistent compliance and application across Gulf South.

Health and Safety Coordinator

Identify training requirements for personnel involved with health and safety issues. Ensure the system tracks training requirements and maintains employee-training records.

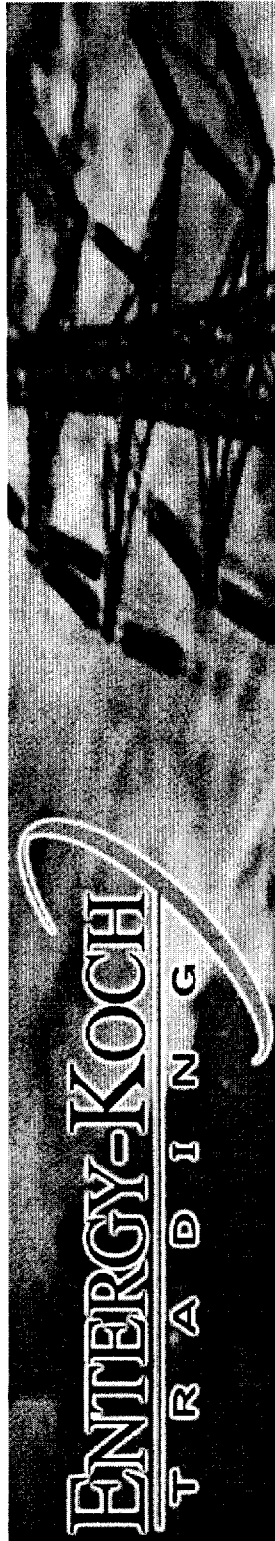
Environmental Health and Safety Analyst

Work with Gulf South personnel to meet DOT Drug and Alcohol requirements for Pipeline operations. Maintain Spill and Leak database for Gulf South and distribute monthly scorecards. Maintain Incident database for Gulf South and distribute weekly incident reports. Ensure all applicable Environmental Health and Safety documents are maintained and available as a company resource (i.e. MSDS, Safety Procedures, Environmental and DOT Manuals).

16

Thursday September 6, 2001

NORTH AMERICA EUROPE



- ▶ EKT Overview
 - Vision and Principles
 - Facts
 - Corporate Execs
- ▶ Business Groups
- ▶ Latest News
- ▶ Career Opportunities
- ▶ Contact Us

Corporate Executives

- **Kyle D. Vann**, President & CEO, Entergy-Koch, LP
- **Dennis J. Albrecht**, Executive Vice President & CFO, Entergy-Koch, LP
- **David A. Sobotka**, President, Entergy-Koch Trading, LP
- **Christopher J. Bernard**, General Counsel, Entergy-Koch, LP
- **Keli D. Shanks**, V.P., Human Resources, Entergy-Koch, LP



Kyle D. Vann **President and Chief Executive Officer, Entergy-Koch, LP**

With more than 30 years of service in the energy business, Mr. Vann was named President and CEO of Entergy-Koch, LP, formed February 1, 2001.

His career in the energy industry began in 1969 with the Baton Rouge Refinery owned by Exxon USA. As a chemical engineer, Kyle held several technical, economic, and managerial positions at the refinery before moving to Exxon USA headquarters in Houston in 1977. At the Houston office, he focused on economics and the supply & trading businesses.

In 1979 he joined Koch Industries (KII) in Wichita, Kansas. During his tenure with Koch, he had numerous assignments. He served as Manager of Oil Field Projects; Manager of KII Projects and Economics; Exec. V.P. of Products Marketing for Koch Refining Company; Director of Koch Management Center; Exec. V.P. of Koch Refining and Chemical Group; President of Koch Supply and Trading and Sr. V.P. Crude Oil and Energy Services. Mr. Vann was then transferred to Houston to provide the senior Koch leadership necessary to fulfill the company's expectations for the region. As Sr. V.P.

and Managing Director, he participated in a broad range of business development and helped direct the company's joint venture with Entergy.

Mr. Vann is an active member of his community. He has been involved with a number of organizations including: the University of Kansas School of Engineering where he has served on the Advisory Board, co-chaired the Chemical Engineering Advisory Board, and was named to the C&PE Hall of Fame in 1999; the University of Kansas Endowment Association Board of Directors and Houston's Executive Board of Directors for Junior Achievement. He attends Bethel Independent Presbyterian Church and is active in several Christian ministries such as FCA, Man In the Mirror, Mars Hill Productions and Priority Associates.

Mr. Vann has given numerous talks to industry organizations and college students on various issues including free market economics, faith in the workplace and the economics of the oil industry.

Mr. Vann holds a Bachelor's degree in Chemical Engineering from the University of Kansas where he was the recipient of numerous awards, honors, and scholarships. He and his wife, Barbara, have four children and five grandchildren.

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Dennis J. Albrecht

Executive Vice President and Chief Financial Officer, Entergy-Koch, LP

After 20 years at Koch Industries, Inc., Dennis brings a wealth of experience and knowledge to his current position - Executive VP & CFO. His duties include overseeing the Treasury Department and the Controllers of Entergy-Koch Trading, LP and Gulf South Pipeline.

In 1981 Dennis started his career at Koch Industries, Inc. (KII) as a Natural Gas Accountant for Koch Hydrocarbon Company. He was later promoted to General Manager of Gas Accounting and Scheduling. In 1987, Dennis became Controller of Koch Supply and Trading. He was responsible for the risk control and accounting for Koch's crude oil and refined products and developed KII's initial mid-office function.

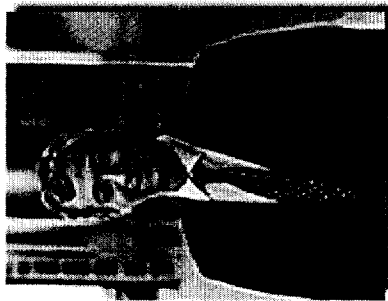
In 1991, Dennis joined the Koch Management Center as an Internal Business Consultant. He was responsible for the education and implementation of Koch's Market Based Management® philosophy within Koch Supply and Trading. In 1992 Dennis was promoted to Vice President of Koch Supply and Trading and was responsible for natural gas and fertilizer trading.

In 1993 he joined Koch Gas Services as Executive Vice President of Trading and was

in 1997, he joined Koch as Executive Vice President of Trading and was instrumental in developing the natural gas trading group. Dennis moved into Koch Agriculture in 1996 to develop the Agriculture trading business for Koch. Dennis moved back to Houston in 1998 to join Koch Energy, Inc. as Controller.

Dennis graduated from Fort Hays State College where he received a Bachelor's of Science in Accounting.

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David A. Sobotka
President of Entergy-Koch Trading, LP

David Sobotka is currently the President of Entergy-Koch Trading, LP, a division of Entergy-Koch LP (EKLP). He holds a BA in Economics from Yale College. He is a past Vice-Chairman of Commodity Exchange, Inc. and has been involved in the creation of several capital market securitizations of commodity risks throughout his career.

David began his career as a Research Analyst at the Federal Reserve Bank of New York. For the past twenty years, he has been involved in all phases of the commodity trading business. From 1979 to 1990, David was a Trader and then a Trading Manager in the precious metals market for Union Bank of Switzerland, Citibank and Lehman Brothers. In 1991, he assumed responsibility for Lehman's energy derivatives business involving the crude oil, fuel oil and refined products markets. David started the natural gas trading desk at Lehman and in 1993, spearheaded the formation of the Citizens Lehman joint venture for power trading. From 1993 to 1997, he was Managing Director of all commodities trading at Lehman and was located in London for most of that time.

In 1997, David joined Koch Industries, Inc. to begin a base metal trading operation in London. In 1998, David moved to Houston to assume the role of President of Koch Energy Trading, Inc., the natural gas, power and weather derivatives trading arm of Koch Industries, Inc. Koch Energy Trading became Entergy-Koch, LP in February of 2001 as a result of the Entergy-Koch joint venture. Currently David is responsible for the origination and trading activities around both physical and financial contracts for gas and power as well as the growing weather derivative business which offers protection against risks associated with variations in temperatures and precipitation.

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Christopher J. Bernard
General Counsel, Entergy-Koch, LP

Before being named General Counsel of Entergy-Koch LP, Mr. Bernard was General Counsel of Entergy Power Marketing Corp (EPMC) based in The Woodlands, Texas. He



joined EPMC in April of 1996.

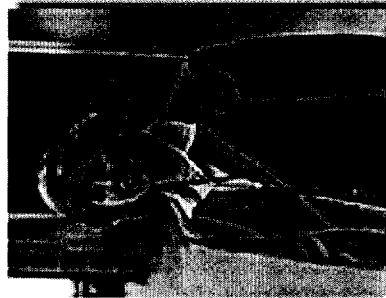
Prior to joining EPMC, Chris was General Counsel of Edisto Resources Corporation and its energy trading subsidiaries.

Chris has twenty-three (23) years of experience in the energy business as both a lawyer and a businessman. His areas of experience include: oil and gas exploration and production, natural gas gathering and processing, and trading of all of the energy commodities. His experience in business and energy law extends from the US to Europe, South America, Australia, Mediterranean Africa and the Pacific Rim of Asia.

Chris holds a Bachelor of Arts in Political Science from Oklahoma State University and a Juris Doctorate degree from the University of Tulsa College of Law. He is a member of the Oklahoma Bar Association and the American Bar Association.

Currently, Chris is an Executive Committee Member of the National Energy Marketers Association and serves as Co-Chair of the Wholesale Power Standard Contract Committee. In addition, he is a member of the Edison Electric Institute's Power Contract Committee.

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Keli D. Shanks

Vice President of Human Resources, Entergy-Koch, LP

Ms. Shanks has a BBA in Accounting from Pittsburg State University in Pittsburg, Kansas.

Keli joined Koch Industries upon graduation from Pittsburg State in 1986. She was an Accountant and later an Accounting Supervisor for Koch Hydrocarbon, Natural Gas division in Wichita, Kansas. She transferred to Houston, Texas to join the Koch acquisition of United Gas Pipeline now known as Gulf South Pipeline. Keli worked in the Customer Service department of that company from 1993 to 1997.

Keli started her career in Human Resources in 1997. She was responsible for the education of Market Based Management in Houston and was instrumental in the overall implementation of Koch's management and business philosophies among the business groups. She later became a Human Resources Leader for both Koch Energy Trading and Koch Gateway Pipeline where she worked on Organization Design and Development, Performance Management and Employee Relations issues.

Keli is the Director of Human Resources for EKLK where she is responsible for the

Human Resources function including Performance Management, Compensation and Benefits, Employee Relations, Recruiting and Payroll.

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Entergy-Koch

***American Gas Association
Financial Forum
May 7, 2001***

***Kyle Vann
President and Chief Executive Officer***

The following constitutes a “Safe Harbor” statement under the Private Securities Litigation Reform Act of 1995:

The following presentation includes forward looking statements, estimates and projections. Actual results and events may, for a variety of reasons, prove to be materially different from those indicated in these forward looking statements, estimates and projections. Factors that could influence actual future outcomes include the effects of changes in law, regulatory decisions, the evolution of competition, changes in accounting, weather, the performance of generating units, fuel prices and availability, financial markets, risks associated with businesses conducted in foreign countries, and changes in Entergy’s business plans, among other factors.

Discussion Outline

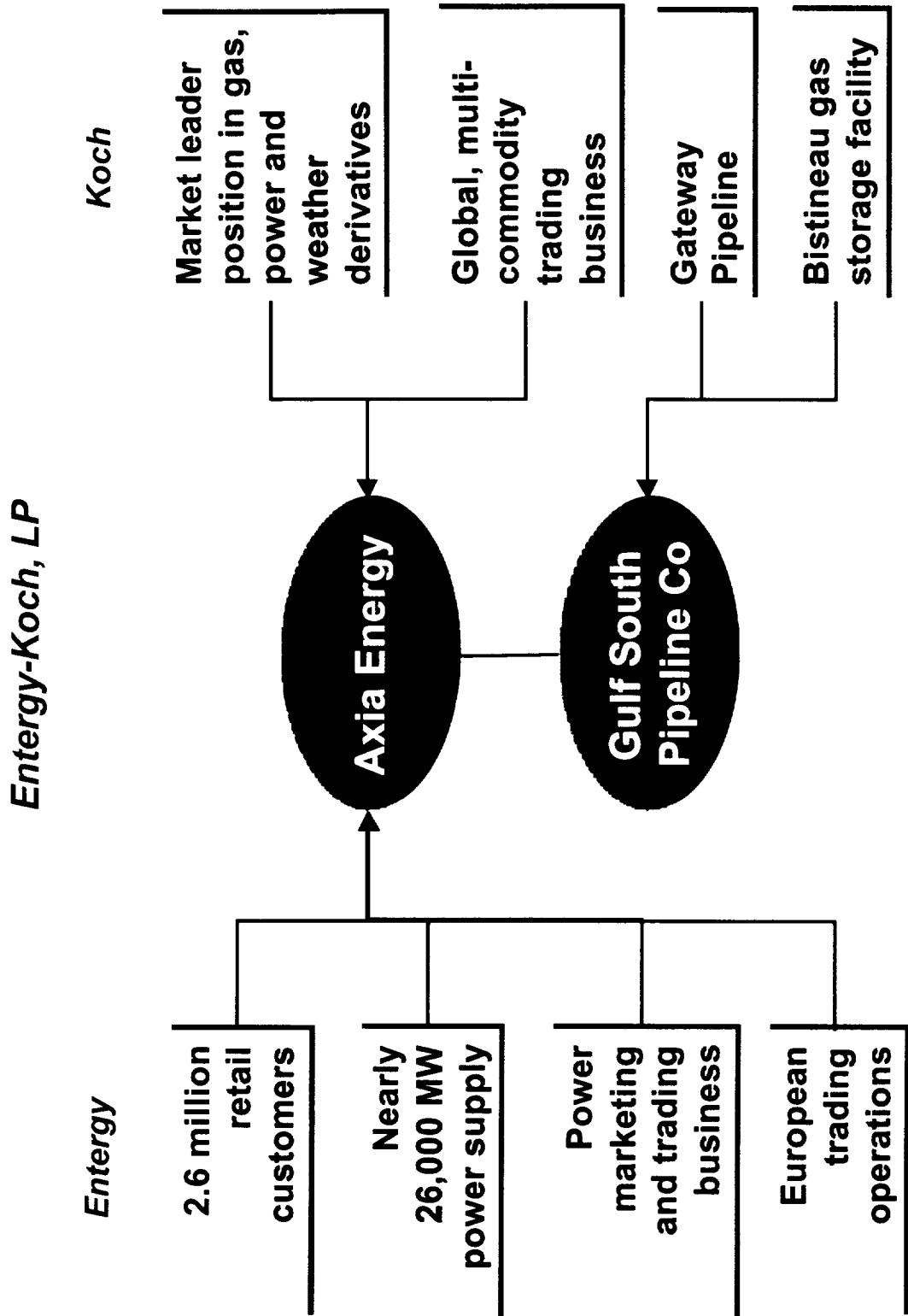
Entergy-
Koch
Overview

Gulf South
Pipeline

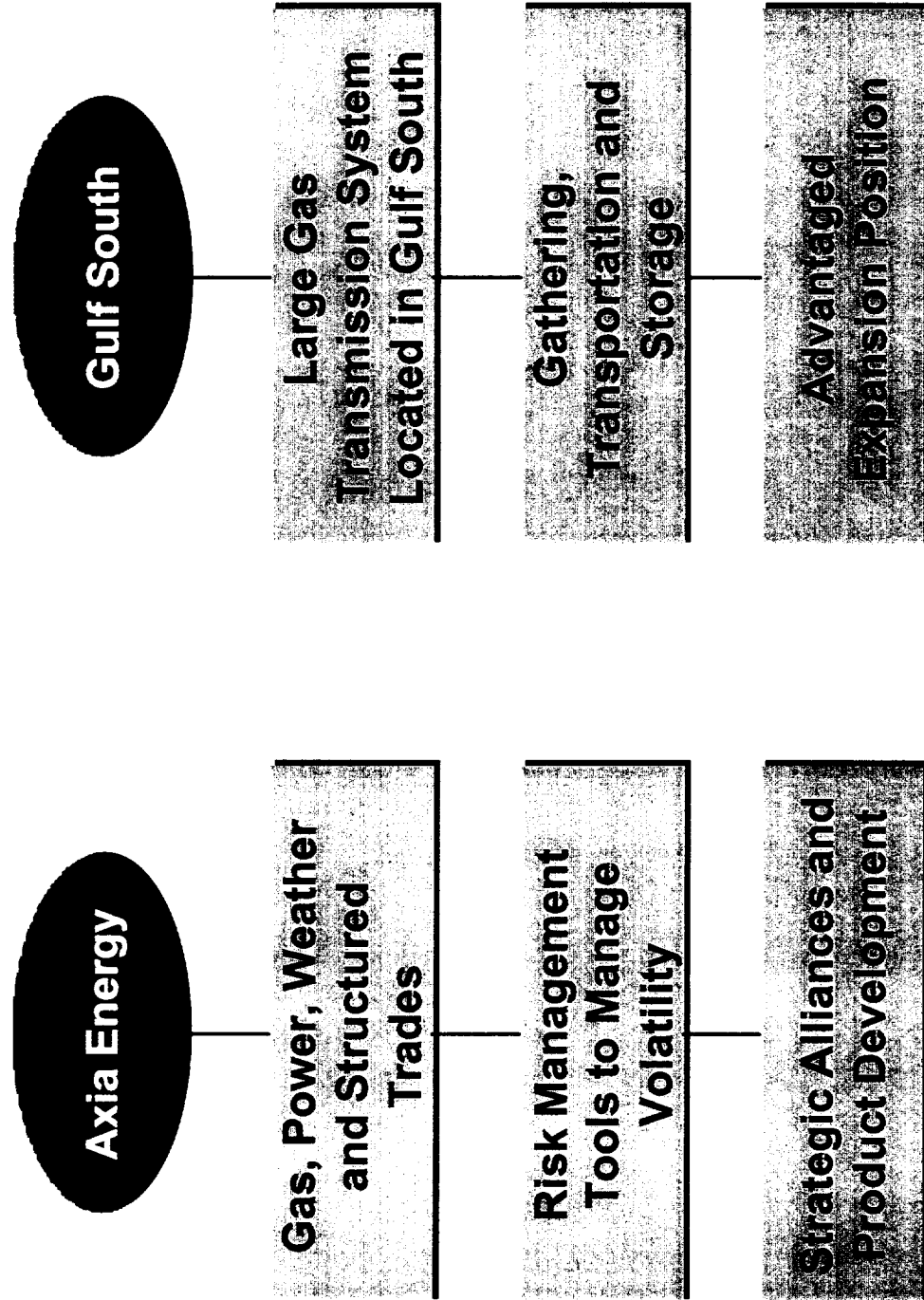
Axia
Energy

Summary

Complementary Assets and Capabilities of Entergy and Koch Form a World-Class Energy Company...



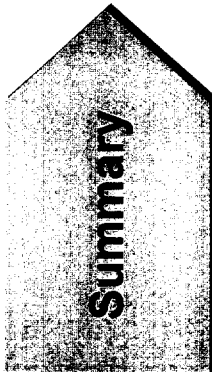
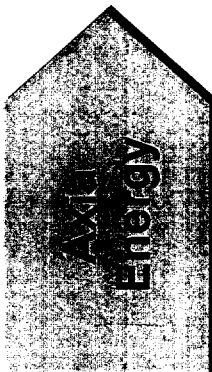
...With a Focused Business Scope



Discussion Outline

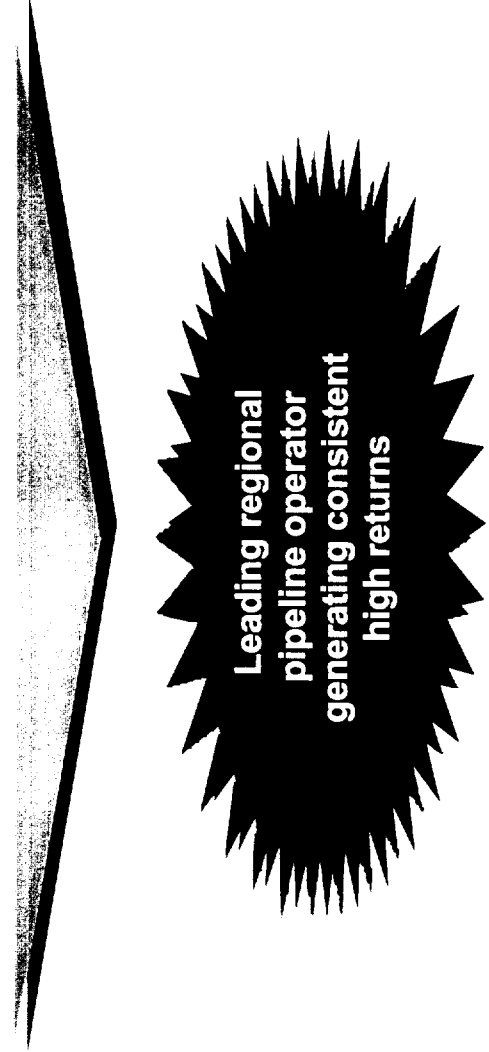


Gulf South
Pipeline



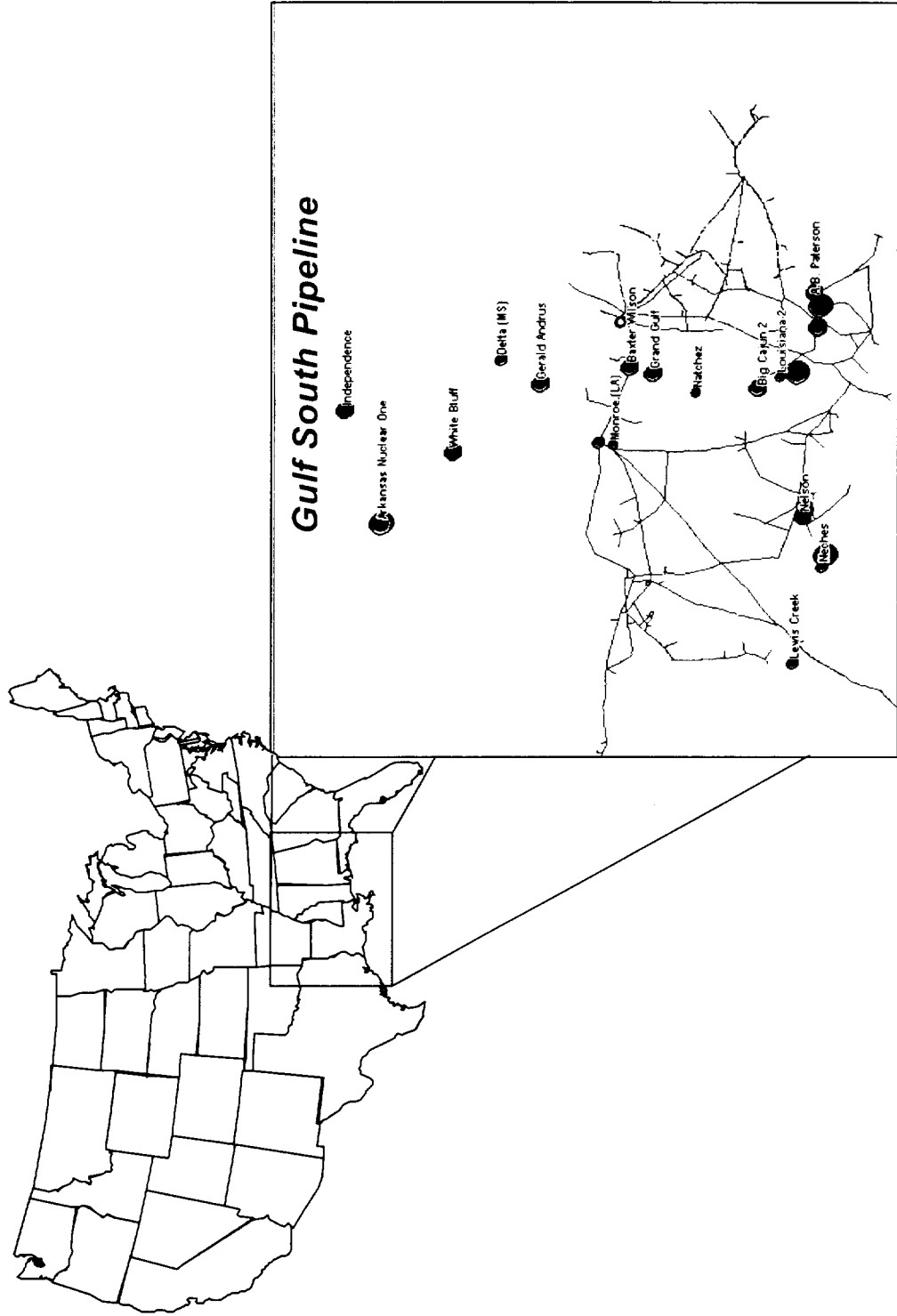
Gulf South Pipeline Will Leverage Its Strong Regional Position and Advantaged Assets

- 1** Capture favorable regional supply and demand to increase throughput
- 2** Continue to achieve top operational performance and low cost position
- 3** Develop additional storage opportunities in region
- 4** Expand diversified sources of supply and customer base
- 5** Achieve safety performance among industry leaders



Gulf South Pipeline Has an Attractive Service Area and Key Interconnects

Gulf South Pipeline Network



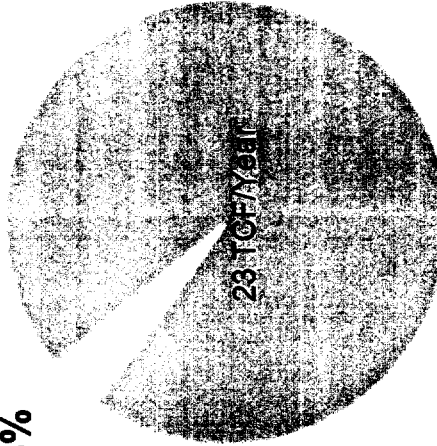
Gulf South Pipeline Holds a Strong Market Position

Miles of Pipeline

Company	2000	Rank
Duke Energy Field Services	57,000	1
Northern Natural Gas	16,459	2
Tennessee Gas Pipeline	14,545	3
Columbia Gas Transmission	12,088	4
Natural Gas Pipeline Company	11,870	5
Southcentral	11,782	6
ANR Pipeline	10,580	7
Transcontinental Gas Pipeline	10,545	8
El Paso Natural Gas	9,894	9
Enogex	9,659	10
Texas Eastern Transmission	9,088	11
Gulf South Pipeline	8,800	12
CNG Transmission (Dominion)	7,583	13
TXU Gas Company	7,264	14
Southern Natural Gas	7,102	15
Kinder Morgan Interstate Gas	7,102	16
Coral Energy	6,500	17
Utilicorp United	6,500	18
Panhandle Eastern Pipe Line	6,336	19
Reliant Energy Gas Transmission	6,118	20

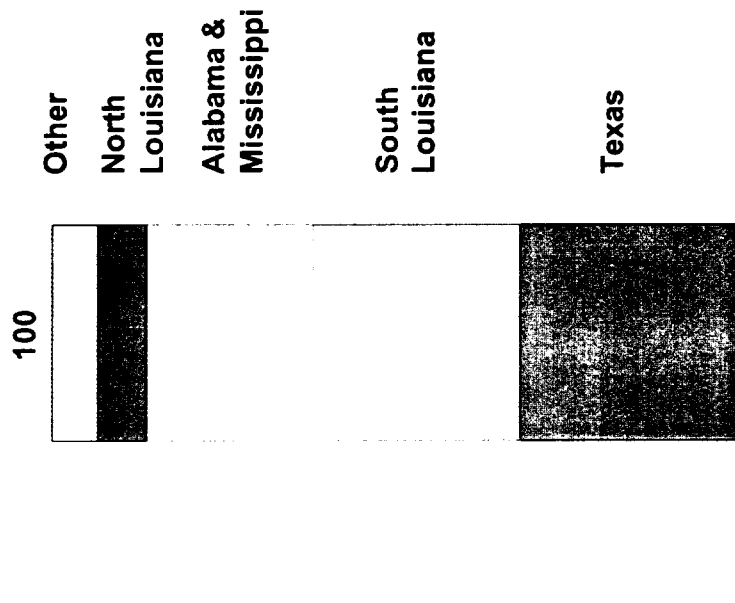
*U.S. Market Share
TCF/Year*

Gulf South Pipeline
1.0 TCF/Year
4%

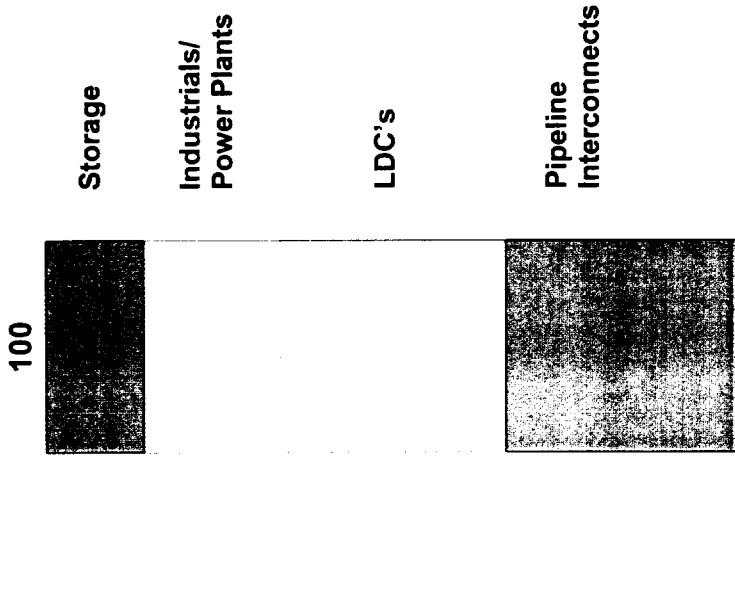


Diversified Supply and Customer Base Support Earnings Stability

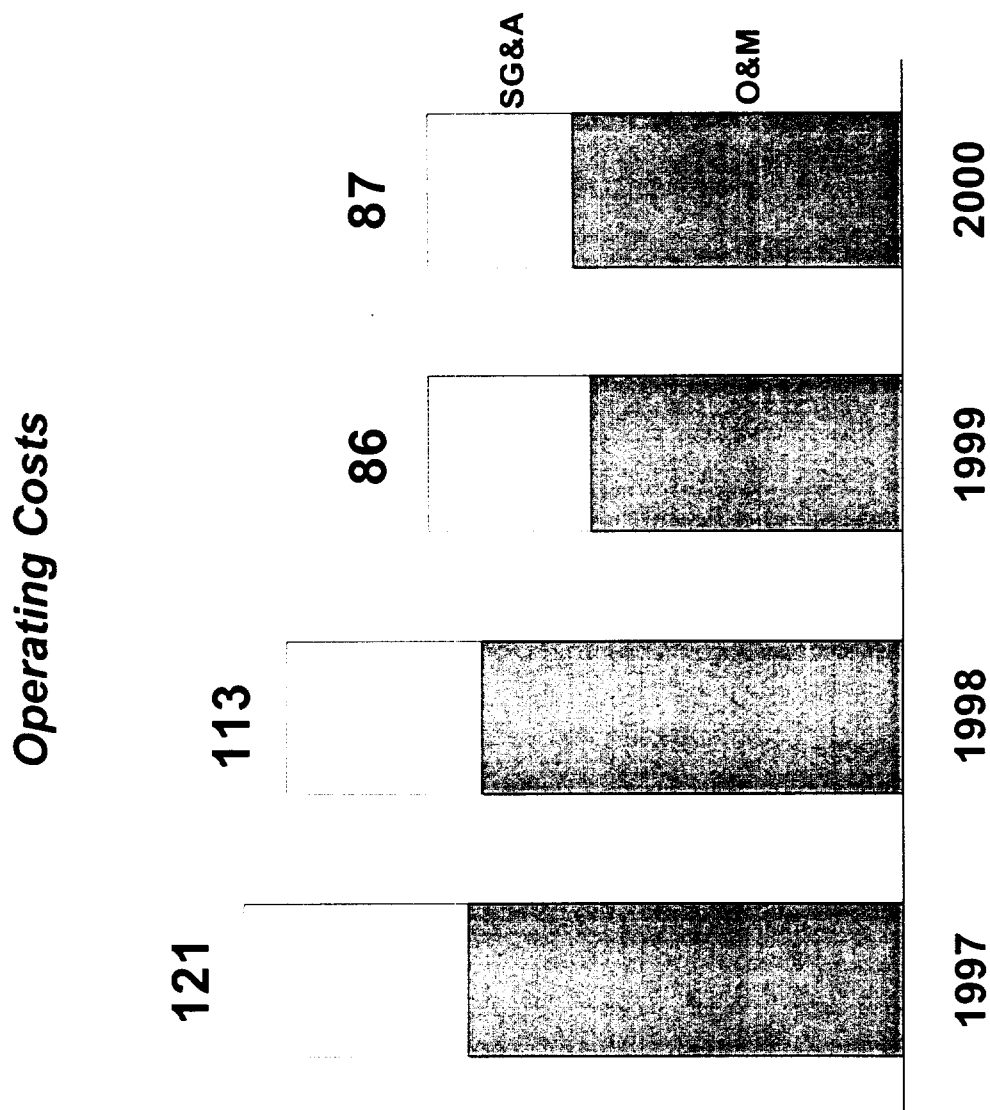
*Pipeline Supply
(Percent)*



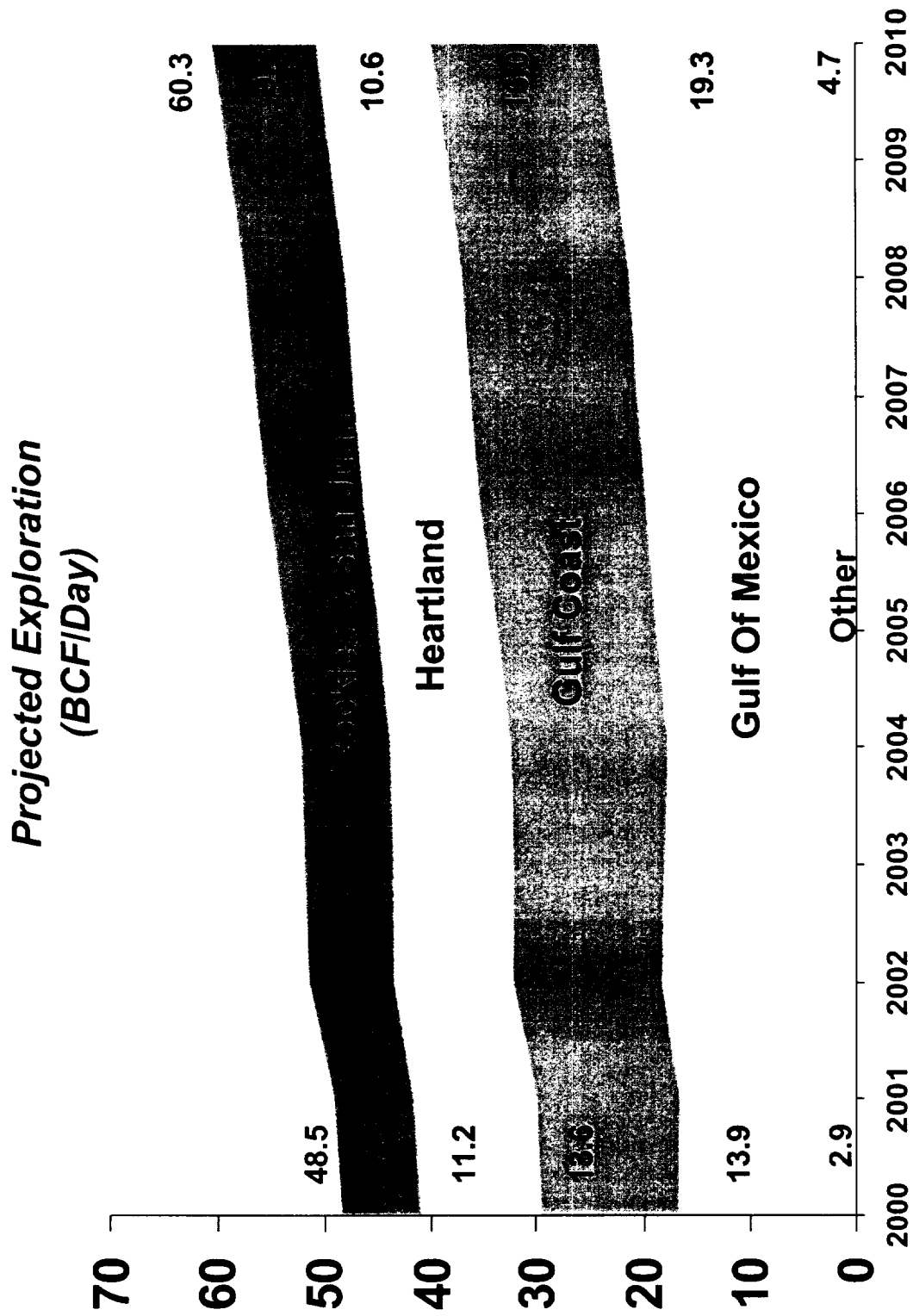
*Pipeline Customers
(Percent)*



Aggressive Cost Reductions Drive Increases in Pipeline Profitability

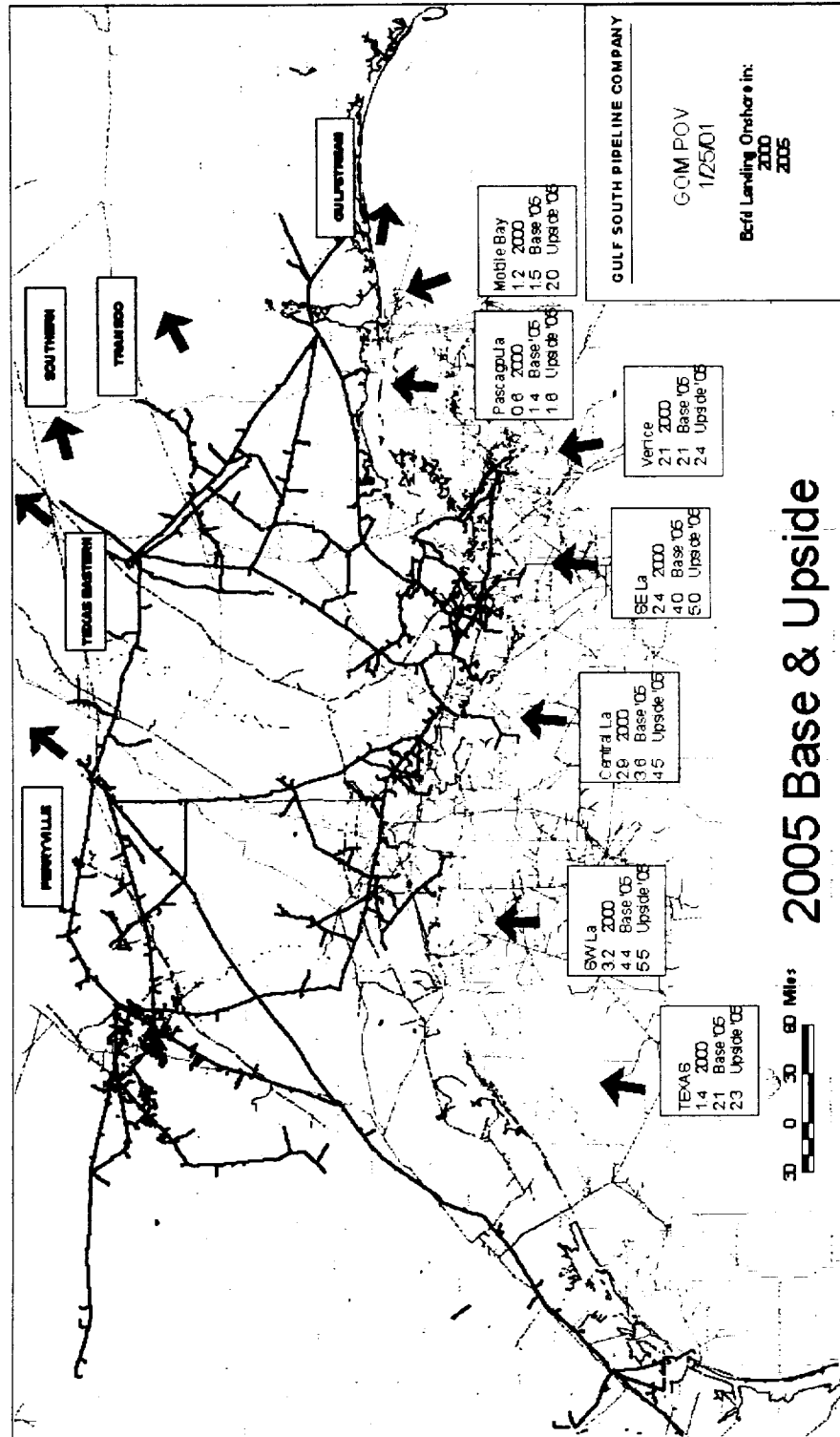


Growth in Gulf Area Exploration Will Create New Opportunities for Pipeline



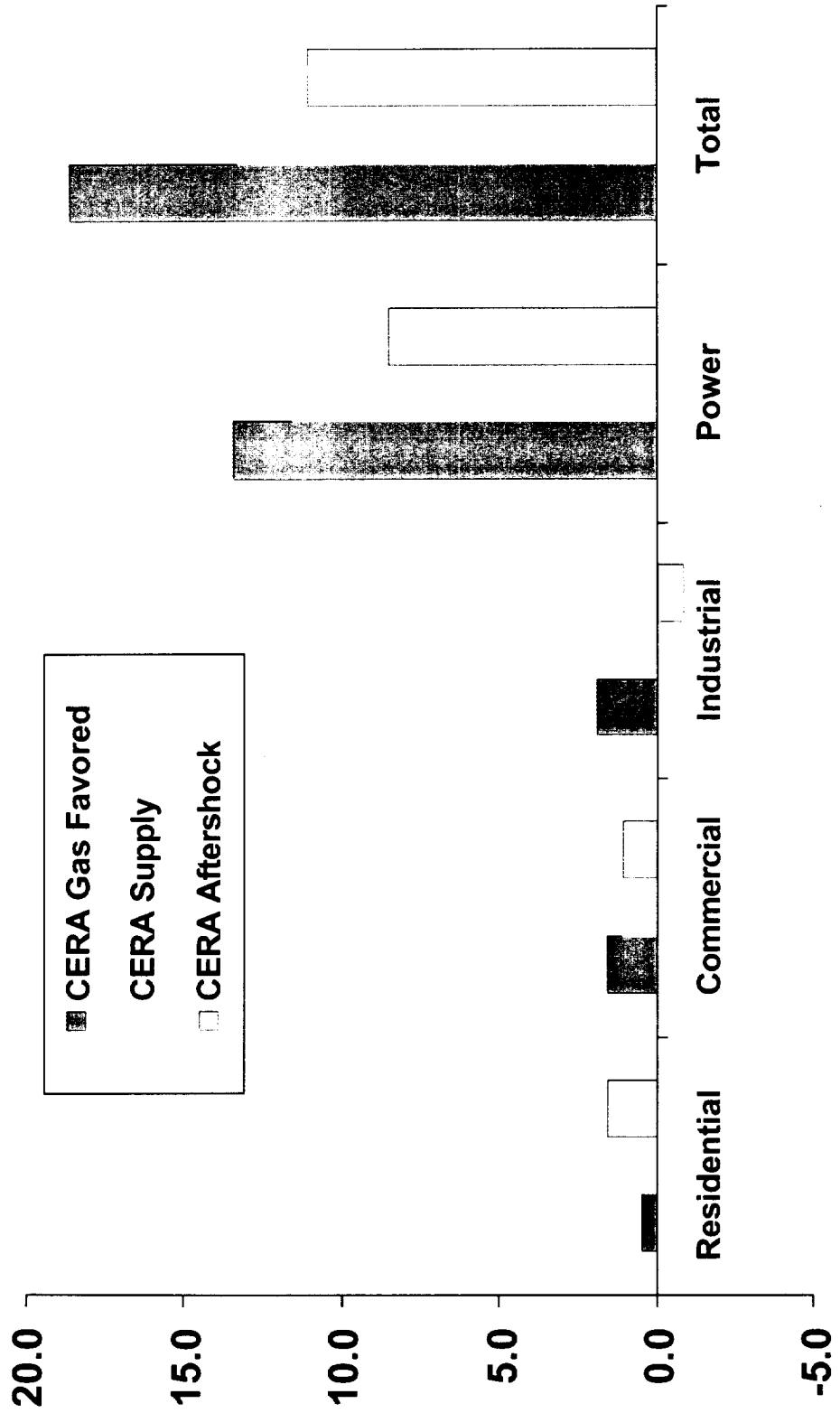
Source: CERA 9/2000 Gas Favored Scenario

Gulf South Pipeline Should Benefit from New Development in Eastern Gulf

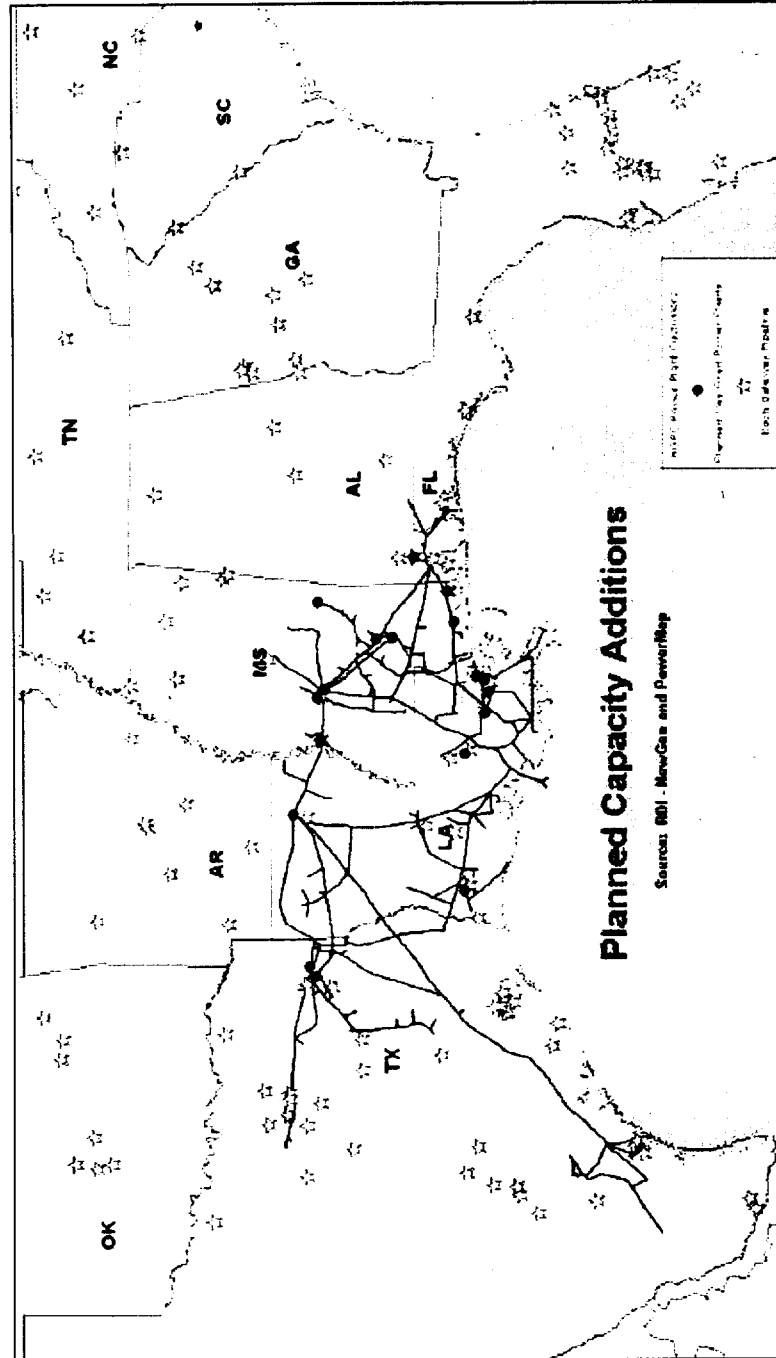


Power Demand Will Create Need for New Gas Supply and Regional Demand/Supply Imbalances

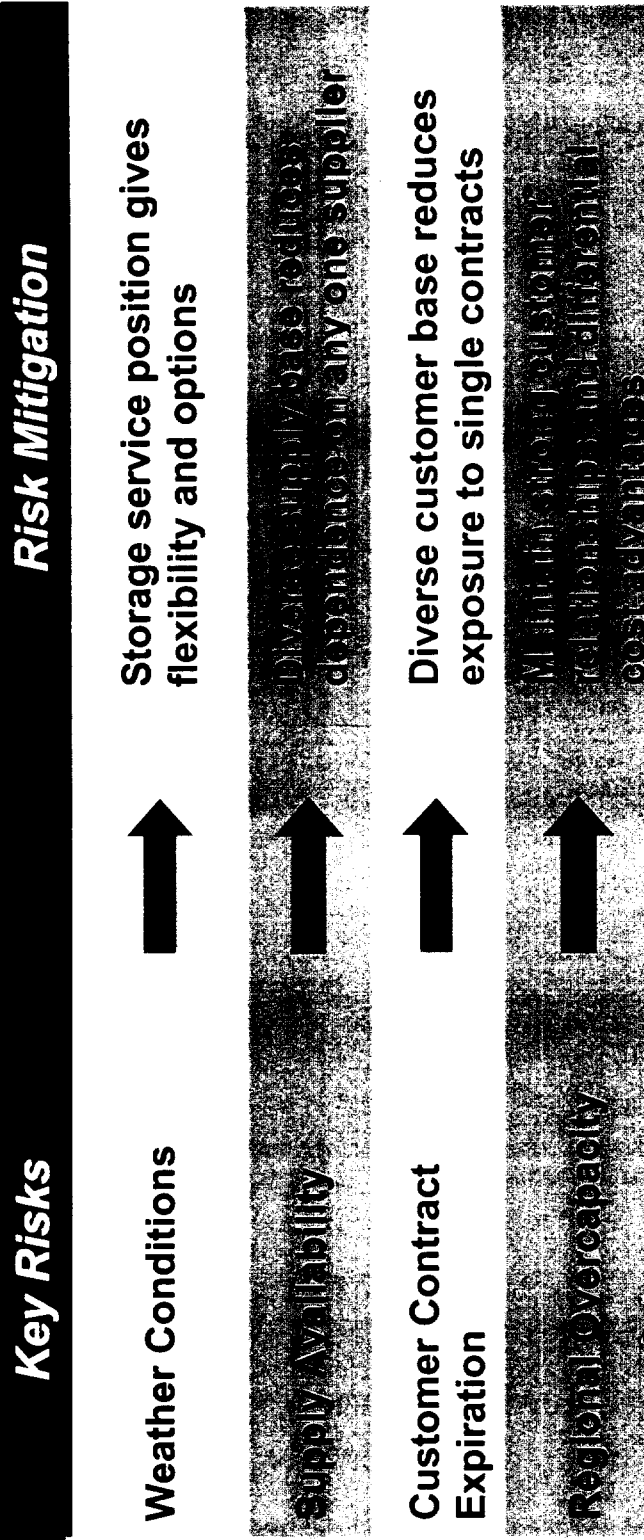
Increase in 2010 Annual Gas Demand Over 2000 Usage (BCF/Day)



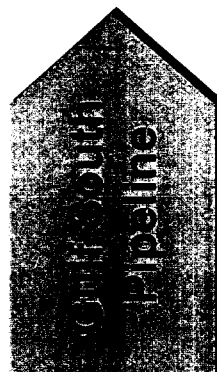
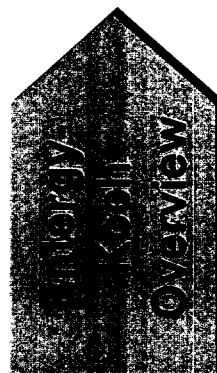
Capacity Additions Will Drive Volatility, Creating Opportunities for Storage and Pipeline Projects



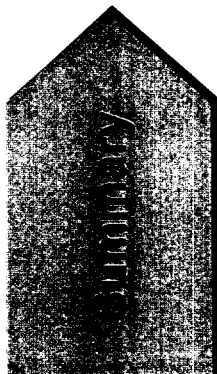
Gulf South Pipeline is Well Prepared for Commercial Risks



Discussion Outline



Axia
Energy



Axia Energy Has the Necessary Scale to Succeed in Both Gas and Power Markets ...

Top 20 Gas Marketers (Bcf/d)

Company	2000	Rank	1999	Rank
Enron	24.0	1	13.4	1
Duke	12.6	2	11.0	2
Reliant	10.9	3	8.8	6
Aquila	10.5	4	10.4	3
Coral	10.2	5	9.8	4
Sempra	10.0	6	7.0	8
Dynegy	9.7	7	8.8	6
BP	8.4	8	5.4	13
El Paso	6.9	9	6.7	9
Mirant	6.9	10	5.4	13
Entergy-Koch*	6.5	11	6.5	11
TransCanada	6.4	12	6.6	10
PG&E	5.8	13	9.2	5
Coastal	5.1	14	5.6	12
Texaco	3.9	15	3.4	17
TXU	3.8	16	3.4	17
AEP	3.8	17	2.7	20
Exxon Mobil	3.7	18	3.6	15
Conoco	3.4	19	3.2	19
Williams	3.3	20	3.6	15

Source: Gas Daily, 2/9/01

Note: * Koch Industries contributed Koch Energy's gas, electricity, and weather derivatives trading operations to Entergy-Koch, L.P.
Entergy-Koch's trading operations opened for business under the name Axia Energy February 1, 2001.

Top 20 Power Marketers (TWh)

Company	2000	Rank	1999	Rank
Enron	578.8	1	380.5	1
AEP	435.1	2	339.9	2
PG&E	283.0	3	204.1	6
Duke	275.3	4	109.6	9
Reliant	201.9	5	111.9	8
Aquila	186.7	6	236.5	3
Mirant	186.0	7	217.7	4
Edison Mission	180.2	8	93.3	10
Constellation	160.0	9	70.0	14
Williams	141.3	10	89.8	11
Dynegy	137.7	11	79.3	13
Entergy-Koch*	118.0	12	142.1	6
El Paso	113.7	13	79.4	12
Avista	105.7	14	135.1	7
Exelon	73.0	15	66.6	15
Sempra	55.0	16	20.0	17
Tractebel	43.7	17	61.5	16
CMS	37.8	18	3.7	19
Coral	27.4	19	16.8	18
BP	25.0	20	0.0	20

Source: Power Markets Week 2/26/01

...And Benefits from Entergy-Koch's Advantaged Credit Rating

Company	S&P	Moody's
Sempra Energy	A	A2
Entergy-Koch	A	A3
Constellation Group	A	A3
Duke Energy Trading	A-	N/A
Enron	BBB+	Baa1
Avista	BBB	Baa2
El Paso Corporation	BBB+	Baa2
Reliant Energy	BBB+	Baa1
Dynegy	BBB+	Baa3
Williams Company	BBB	Baa2
Mirant	BBB-	Baa2
Edison Mission	BBB-	Baa3

Axia Energy Expects to Rank in Top 3 Electricity Derivatives Categories

Electricity

SWAPS - Western

1. El Paso Energy
2. Aquila Energy
3. Koch Energy Trading

SWAPS - Central

1. El Paso Energy
2. Koch Energy Trading
3. Dynegy

SWAPS - Eastern

1. El Paso Energy
2. Enron Corp.
3. BP

OPTIONS - Western

1. El Paso Energy
2. Aquila Energy
3. Koch Energy Trading

OPTIONS - Central

1. El Paso Energy
2. Dynegy
3. Koch Energy Trading

OPTIONS - Eastern

1. El Paso Energy
2. Enron Corp.
3. Koch Energy Trading

Gas

NYMEX LOOK-ALIKE

SWAPS

1. Enron Corp.
2. Bank of America
3. Koch Energy Trading

OPTIONS

1. Enron Corp.
2. El Paso Energy
3. Koch Energy Trading

SWAPS

1. Enron Corp.
2. Koch Energy Trading /
El Paso Energy

OPTIONS

1. Enron Corp.
2. Bank of America
3. El Paso Energy

BASIS

Axia Energy's Strategy Is Focused on High-Margin Energy Opportunities

1

Focus on energy and weather-related products with strong emphasis on analytics

2

Leverage base assets and wholesale trading capabilities to capture higher-margin opportunities

3

Grow broader U.S. and European business from profitable alliances with customers

4

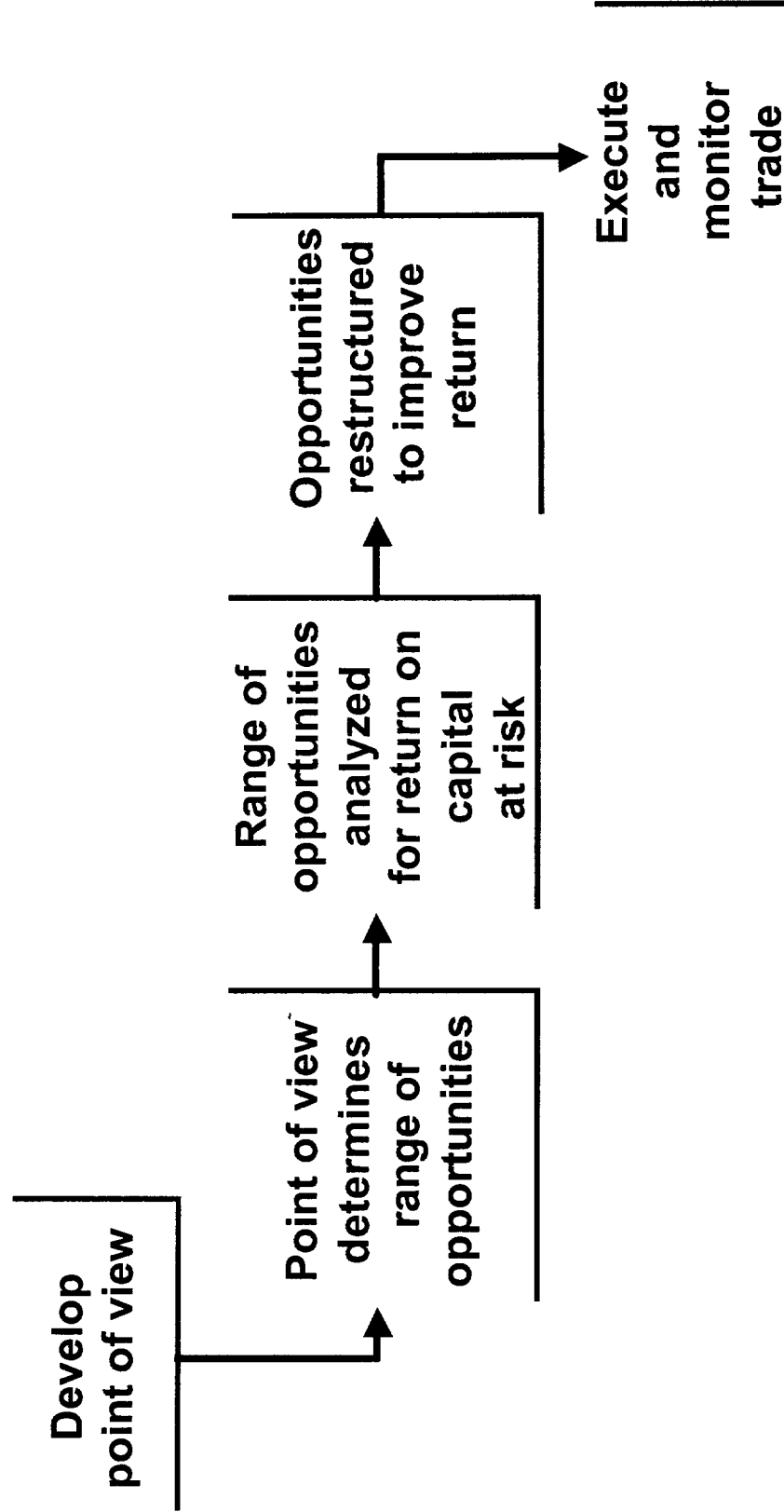
Long-term growth through continued new product development



Top three in energy trading
(return on capital at risk)

Knowledge Based Systems Form the Foundation of Axia Energy's Trading Activities

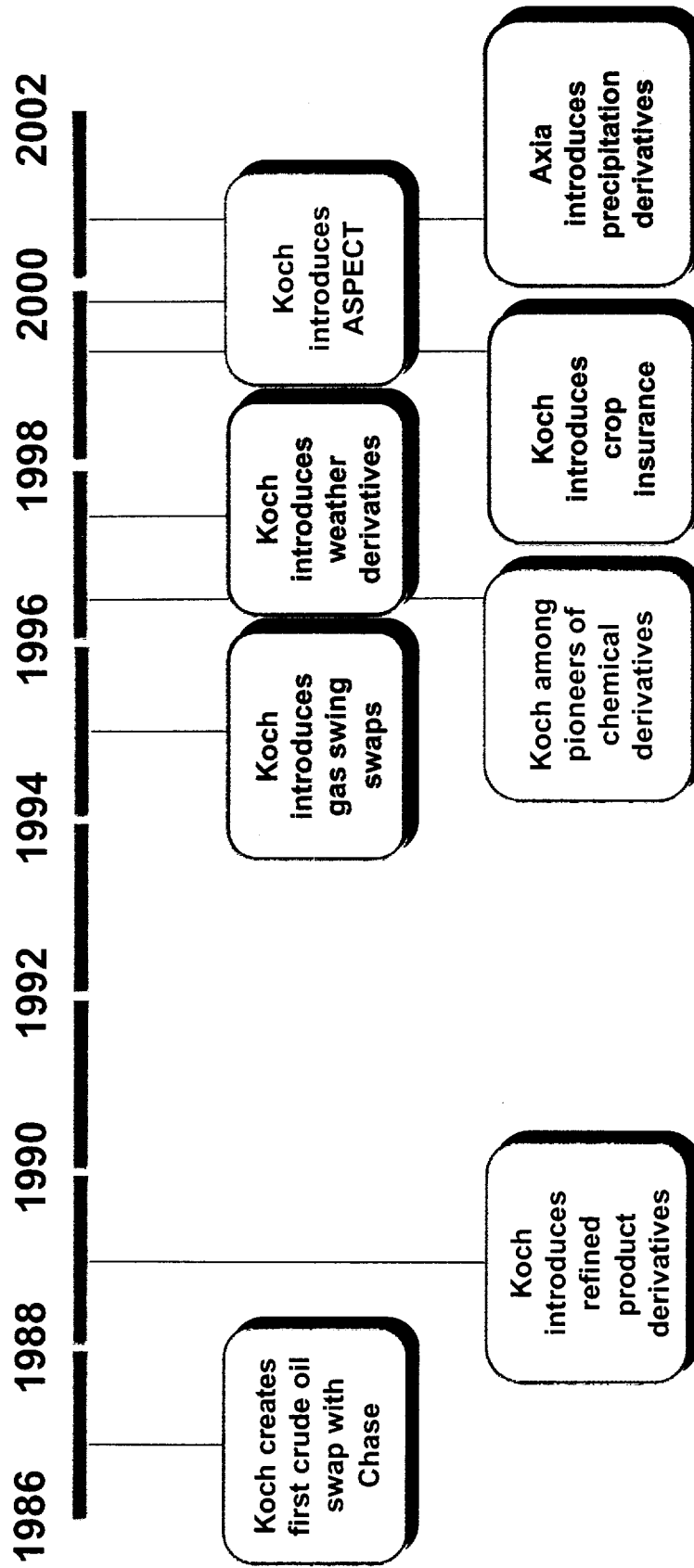
Trading Process



Knowledge Based Systems and Analytical Capabilities

Axia Energy Is Building on Koch's Product Development Track Record to Create New Opportunities

Koch Product Timeline



Products developed by Axia Energy employees

Axia Energy Is the Market Leader in Weather Derivatives

Weather Derivatives

Rankings

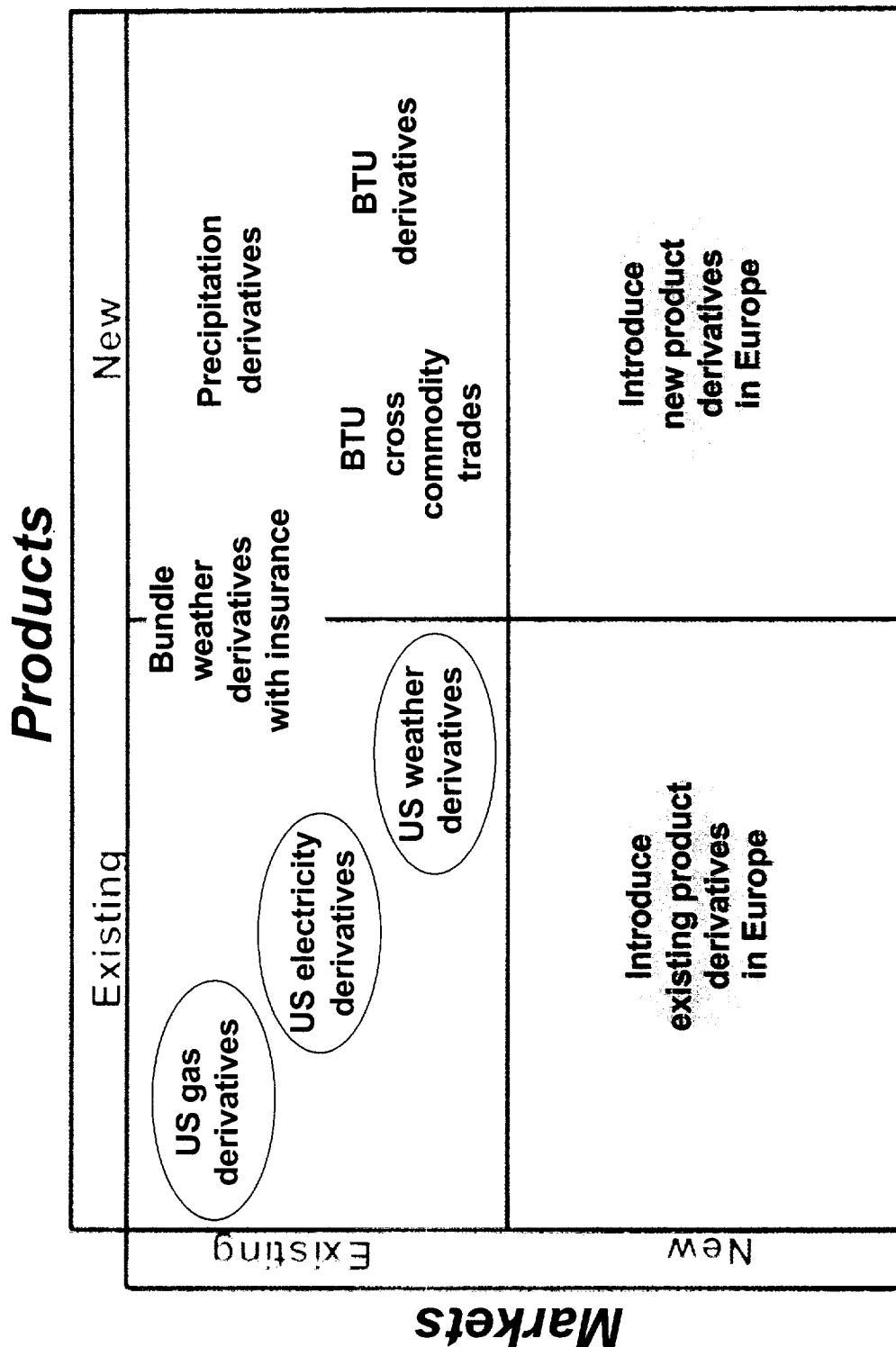
1. Koch Energy*
2. Enron
3. Aquila Energy

Market Share

25-30%

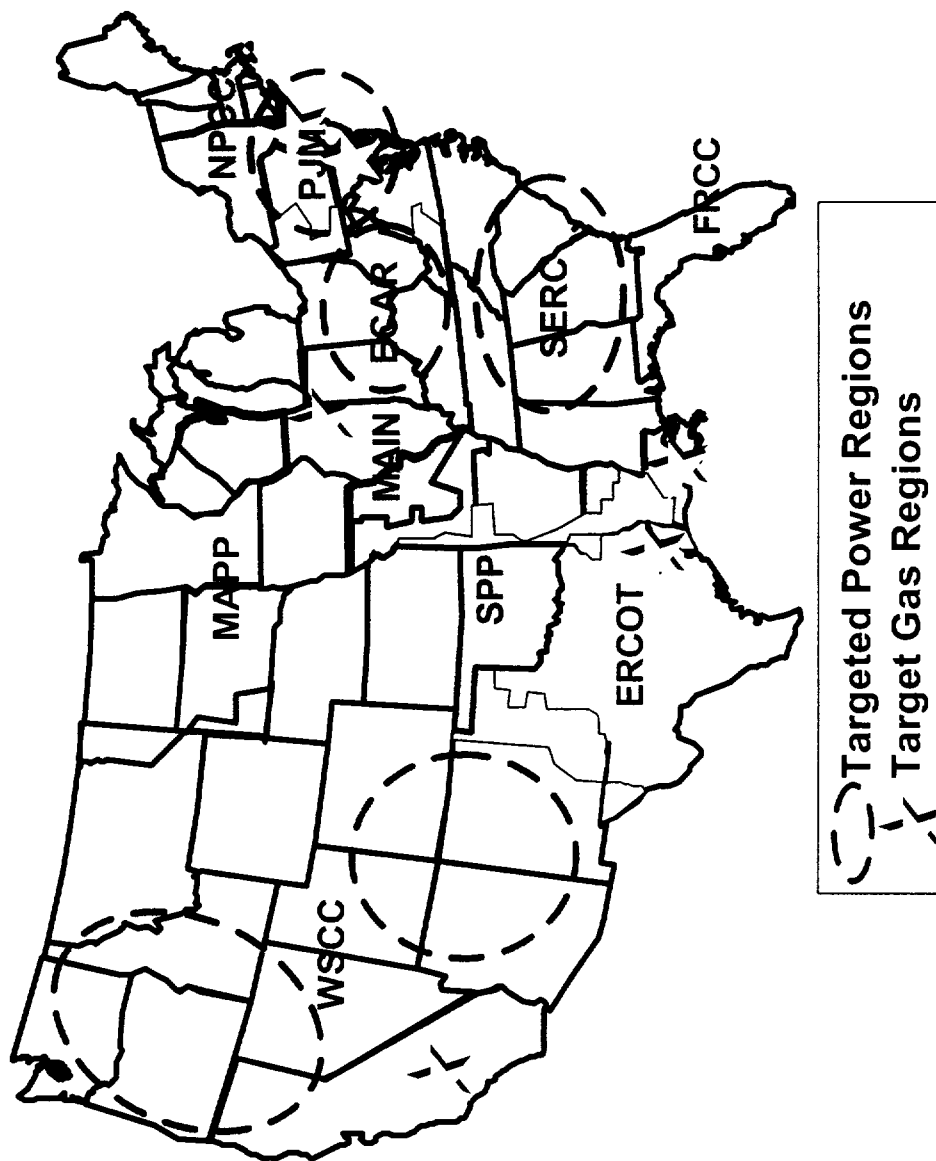
Note: Notional value of weather derivatives trading is estimated at \$1.0 to \$1.5 billion per year.
*Koch Industries contributed Koch Energy's gas, electricity, and weather derivatives trading operations to Entergy-Koch, L.P. Entergy-Koch's trading operations opened for business under the name Axia Energy February 1, 2001.

Axia Energy Will Develop New Energy-Related Markets and Products

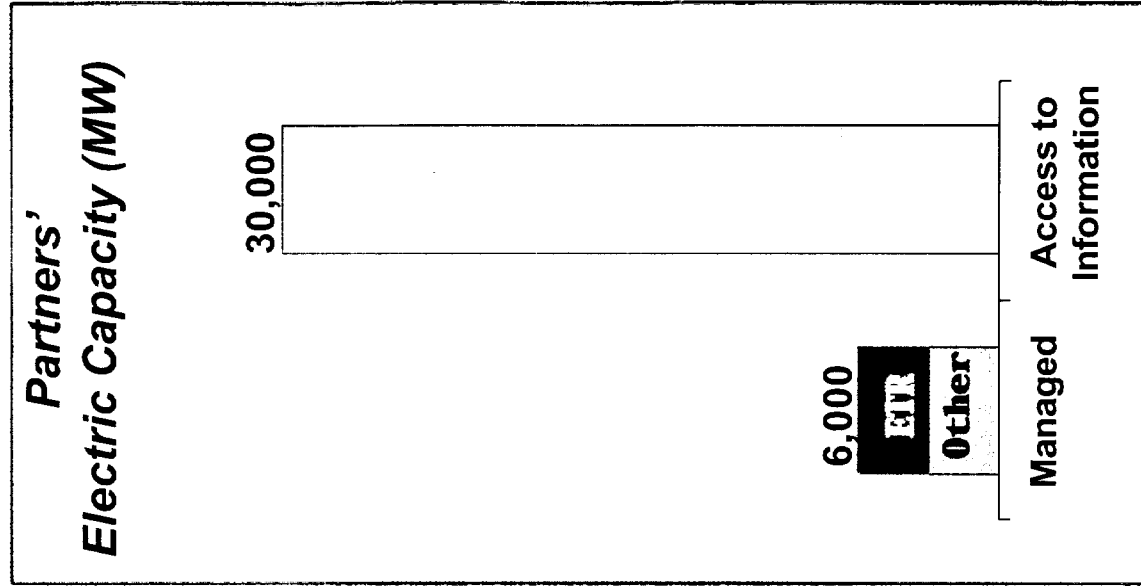
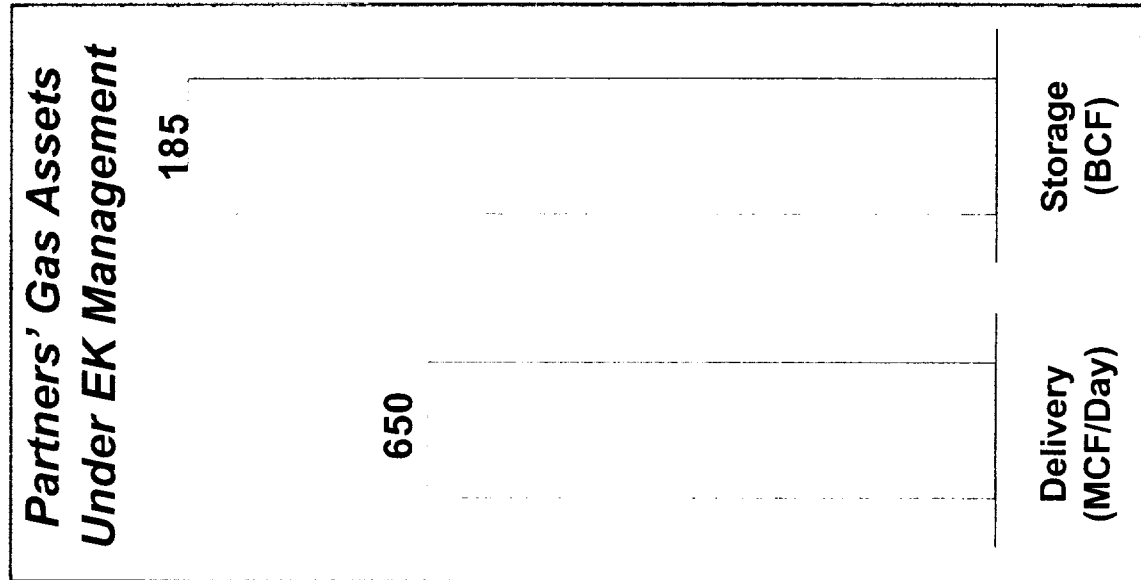
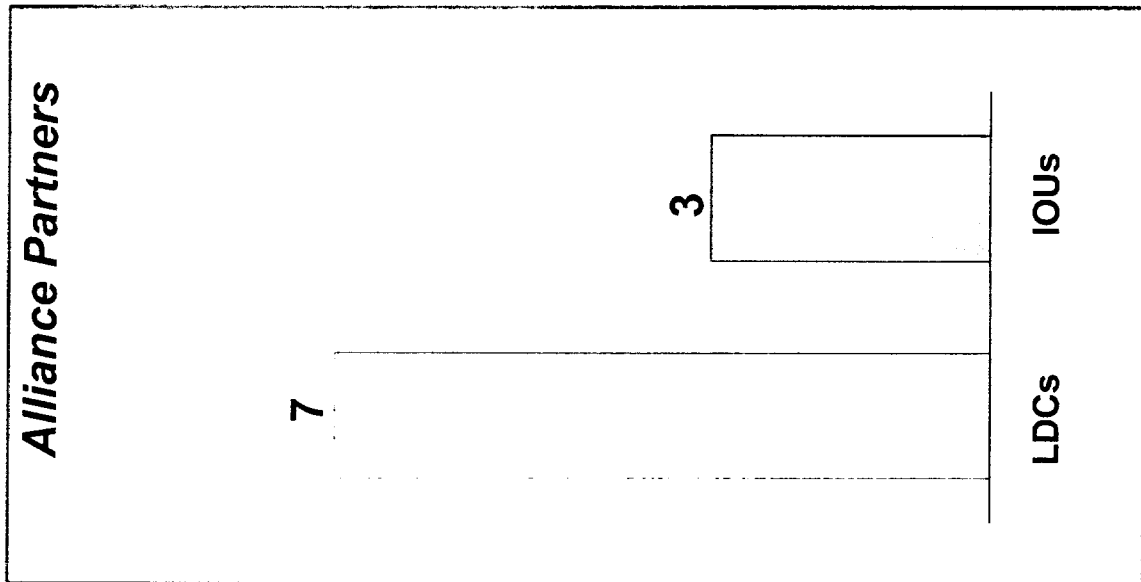


Axia Energy Emphasizes A National Grid of Alliances for Gas and Power Trading

Key Regions

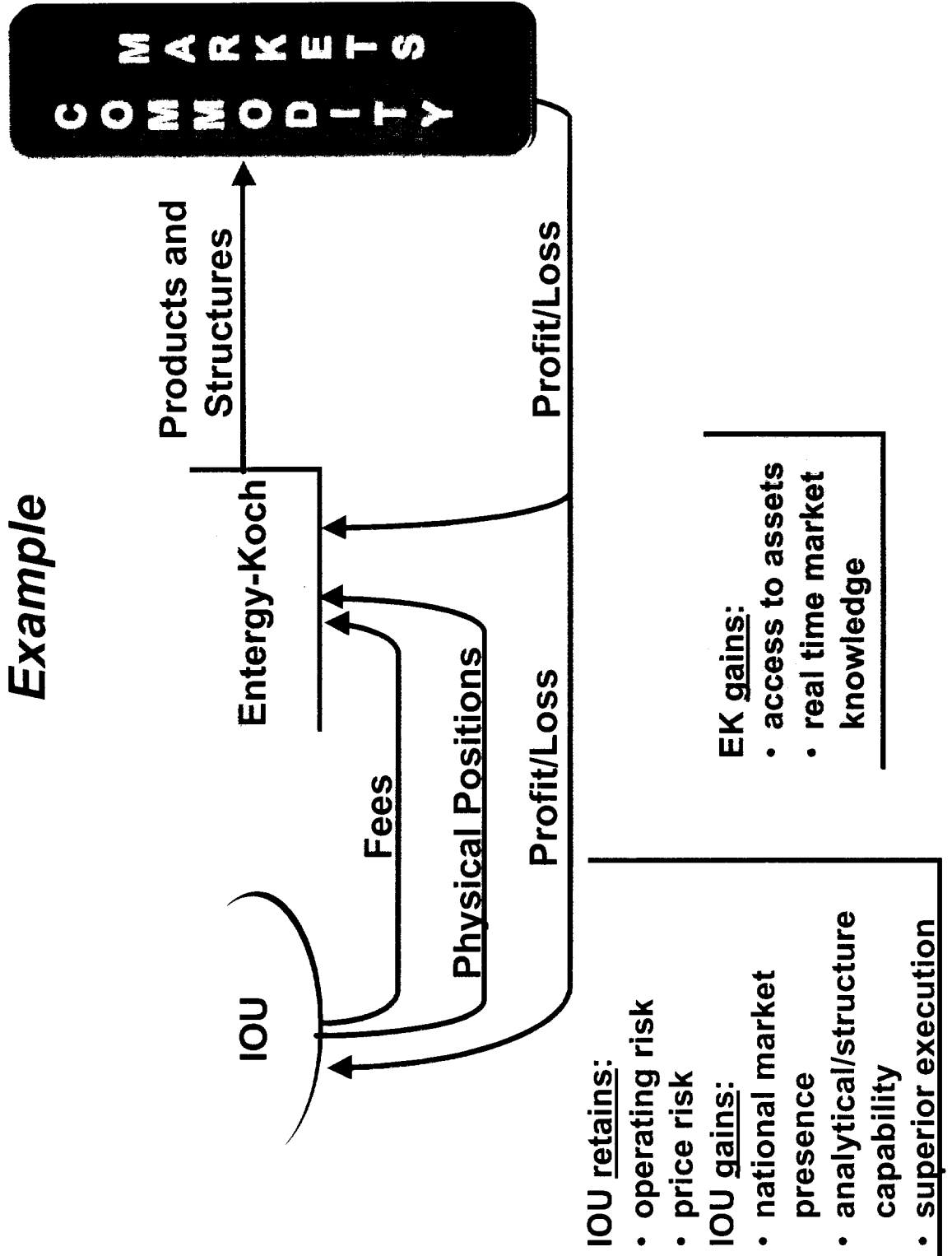


Alliances In Key Regions Support Trading Strategy

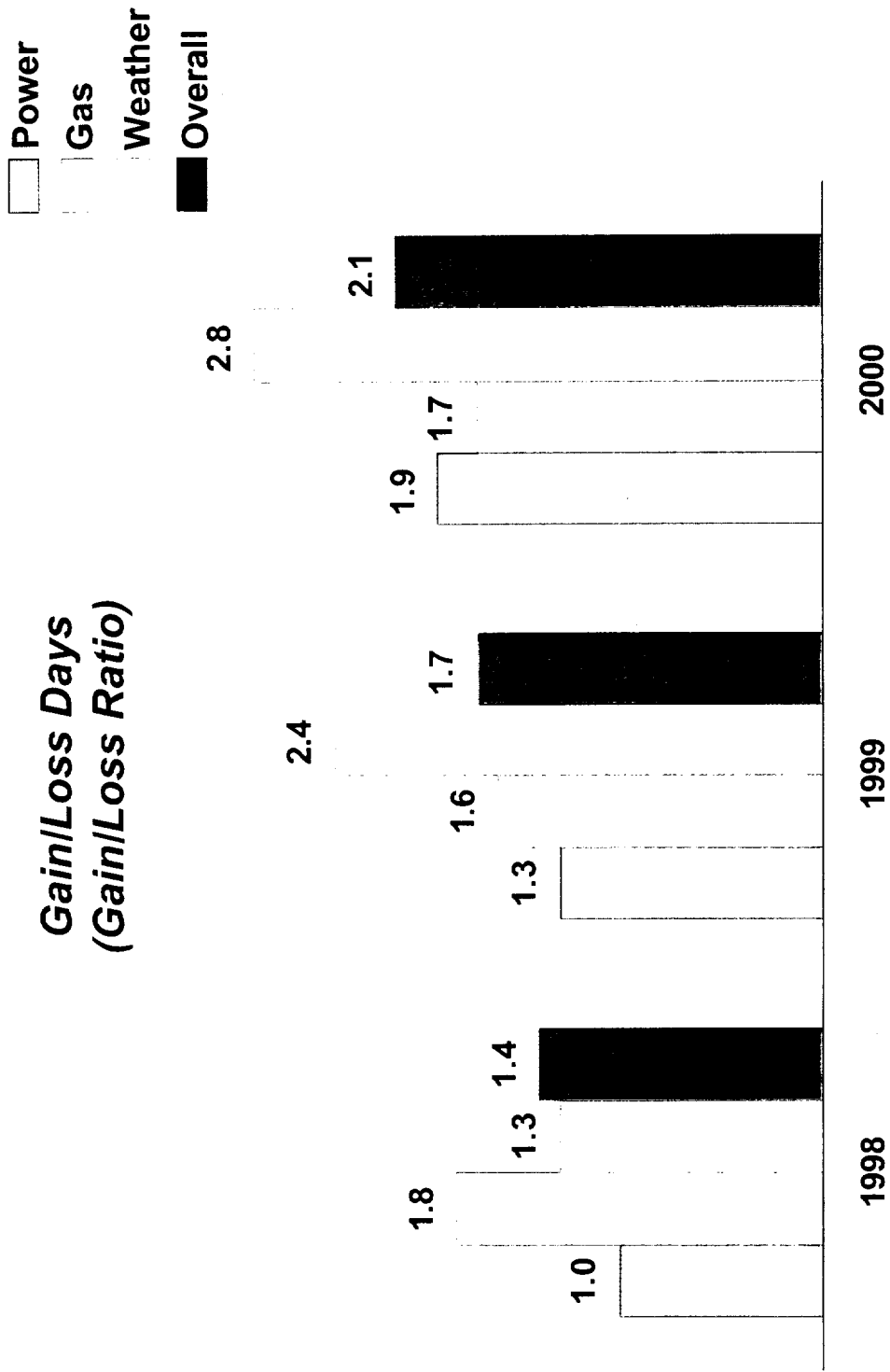


Trading Ventures Can Be Designed to Meet Alliance Partner's Needs

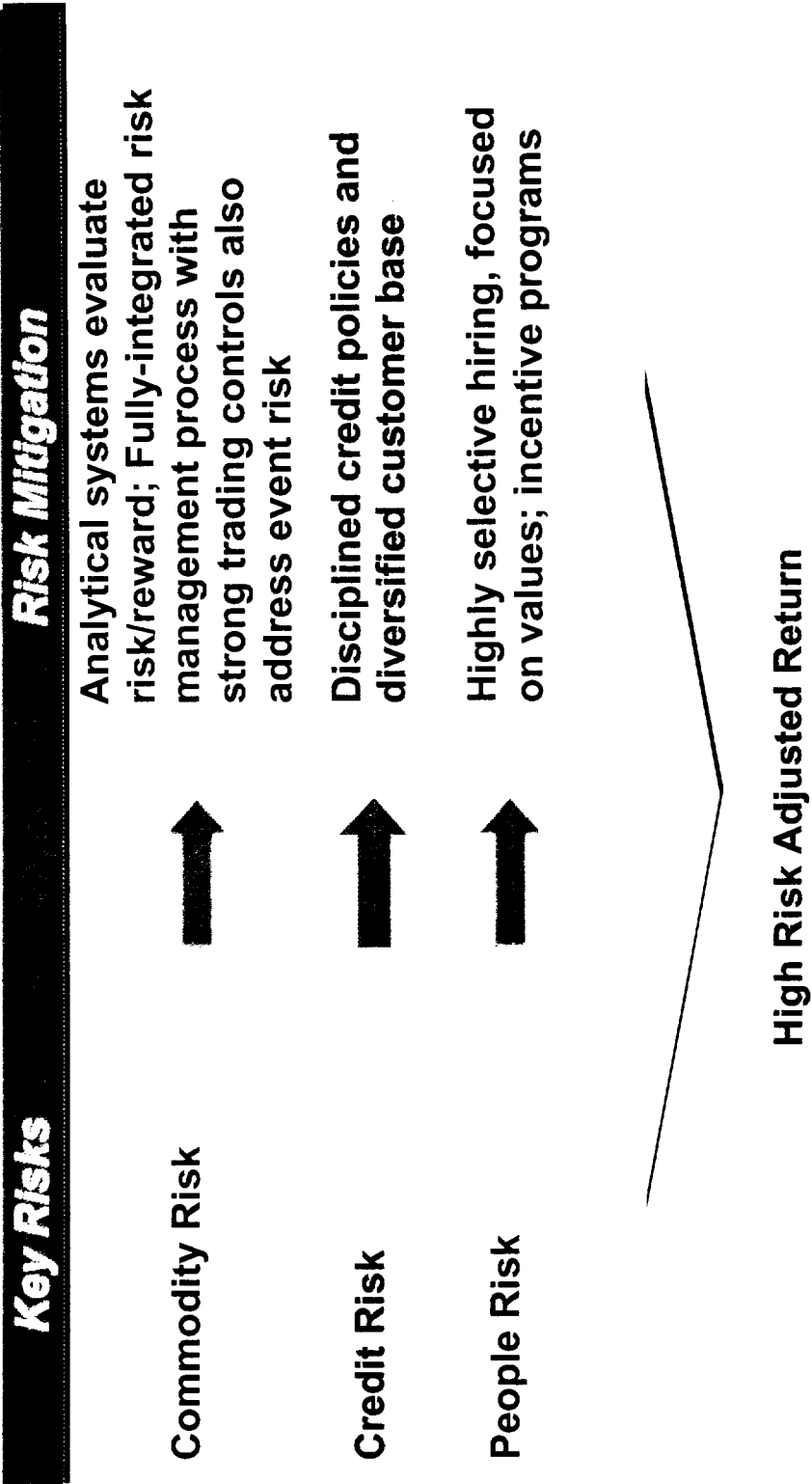
Example



Axia Energy Will Build on Koch Energy's Consistently Successful Trading Record



Axia Energy Has Processes and Expertise to Mitigate Trading Risks



Discussion Outline

Entergy-
Koch
Overview

Gulf South
Pipeline

Axia
Energy

Summary

Entergy-Koch Joint Venture Leverages Complementary Combination of Assets and Trading

Advanced Trading Strategies

Years of Sustained Trading Profitability

Weather Derivatives

30% of Market
(Market Leader)

Structured Products

Top 3 in Energy Derivatives

Physical Gas Trading

6 - 7 BCF/d

Financial Gas Trading

60 - 80 BCF/d

Electricity Trading

110M MWh

Strategic Gas Assets

8,800 Mile Pipeline (Gulf South)
Gas Storage (62 BCF)

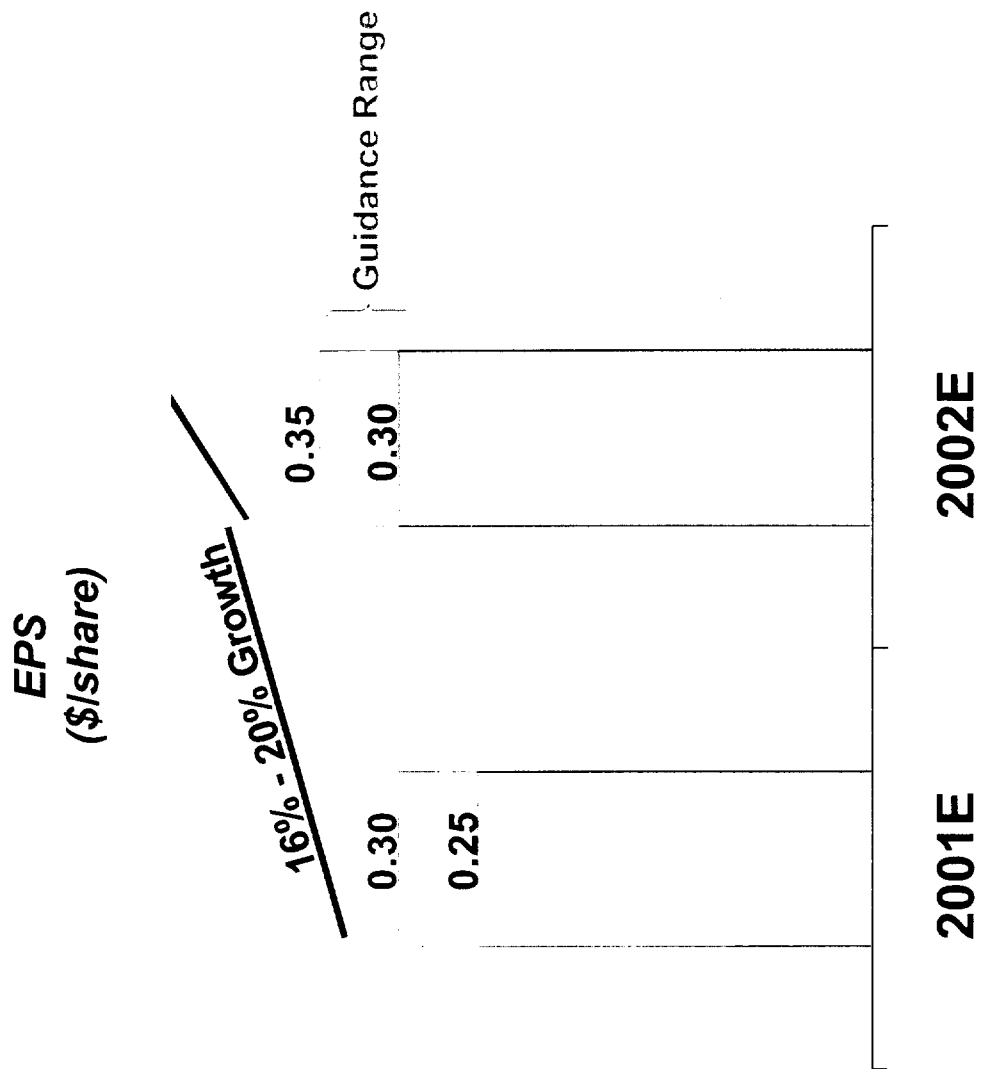
Alliance Partners

6,000 MW (mgt)
30,000 MW (info)
Gas Delivery (650 MCF/D)
Gas Storage (185 BCF)

Strategic Power Assets

>20,000 MW (After Dereg)
100-150 MBPD (Resid Gas Switching)

Entergy-Koch Will Make a Significant Contribution to Entergy's EPS in Its First Year



Entergy-Koch

***American Gas Association
Financial Forum
May 7, 2001***

***Kyle Vann
President and Chief Executive Officer***

Kyle Vann, President and Chief Executive Officer Entergy-Koch, LP



With more than 30 years of service in the energy business, Mr. Vann was named President and CEO of Entergy-Koch LP, formed February 1, 2001.

His career in the energy industry began in 1969 with the Baton Rouge Refinery owned by Exxon USA. As a chemical engineer, Kyle held several technical, economic, and managerial positions at the refinery before moving to Exxon USA headquarters in Houston in 1977. At the Houston office, he focused on economics and the supply & trading businesses.

In 1979 he joined Koch Industries in Wichita, Kansas. During his tenure with Koch, he had numerous assignments. He served as Manager of Oil Field Projects; Manager of KII Projects and Economics; Exec. V.P. of Products Marketing for Koch Refining Company; Director of Koch Management Center; Exec. V.P. of Koch Refining and Chemical Group; President of Koch Supply and Trading and Sr. V.P. Crude Oil and Energy Services. Mr. Vann was then transferred to Houston to provide the senior Koch leadership necessary to fulfill the company's expectations for the region. As Sr. V.P. and Managing Director, he participated in a broad range of business development and helped direct the company's joint venture with Entergy.

Mr. Vann is actively involved with a number of organizations including: the University of Kansas School of Engineering where he has served on the Advisory Board, co-chaired the Chemical Engineering Advisory Board, and was named to the C&PE Hall of Fame in 1999; the University of Kansas Endowment Association Board of Directors and Houston's Executive Board of Directors for Junior Achievement.

Mr. Vann holds a Bachelor's degree in Chemical Engineering from the University of Kansas where he was the recipient of numerous awards, honors, and scholarships.

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**IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION**

**P.D. HAMILTON, Individually and as
Trustee of the Prentice Dell Hamilton and
Florine Hamilton Family Trust**

§
§
§

vs.

§
§

CIVIL ACTION NO. 9:01-cv-00132

**KOCH INDUSTRIES, INC., Individually
and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
GS PIPELINE COMPANY, L.L.C.,
ENTERGY-KOCH, L.P., and
EKLP, L.L.C.**

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JURY

AFFIDAVIT OF JOHN FREEMAN

**THE STATE OF TEXAS
COUNTY OF ANGELINA**

§
§
§

KNOW ALL MEN BY THESE PRESENTS:

**BEFORE ME, the undersigned authority, on this day personally appeared JOHN
FREEMAN, who after being duly sworn while under oath, deposes and states as follows:**

I am over eighteen (18) years of age, of sound mind, have never been convicted of a felony, and am otherwise competent to make this Affidavit. The information contained in this Affidavit is based upon my personal knowledge and is true and correct.

I live off of FM 819, at mail Rt., 1, Box 412, Diboll, Texas; and have been at this address for 44 years. The Koch/United pipeline runs behind my house, between my house and my daughters house, and then between my mother-in-laws house and my son's house all through a residential community. In the years before Koch took over the pipeline, and for two or three years thereafter, it was regularly maintained. The property was mowed and the crossings near the property lines were free of brush and debris. Workers would check the meter station

regularly. Beginning within about three years after Koch posted their signs and took over the maintenance, no one came out to check or maintain the property around the pipeline. I have had to keep the area mowed myself.

Approximately ten to fifteen years ago, a telephone type pole next to the meter station which held a box fed by an electrical meter fell onto the meter station behind my house, driving one end of the perimeter protective pipe halfway into the ground. (See pictures #1, #2, and #3 attached). After some time, Koch finally came out and disconnected the guidewire and took the box, leaving the pole and cable. I finally had to remove and dispose of the pole and cable approximately one year later.

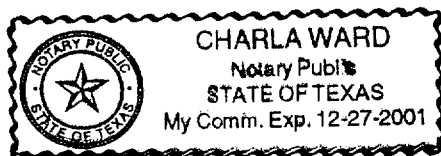
I am a retired electrician by trade, so I am concerned for the lack of attention and maintenance that Koch has given this area, as I know that problems can occur if the meter stations are not maintained properly. This same pipeline crosses my mother-in-laws property, and has another meter station on it. (See picture #4 attached). Koch has failed to maintain this property also, so I have mowed and kept it cleared. They have failed to keep the grass and debris cleared from the meter station as well. The fence that divides my property from my neighbors is grown over with brush and you can barely see the faded posts where the pipeline crosses. There are no signs on the fence to designate the pipeline crossing onto my neighbors property. (See picture #5 attached).

Although these are small examples of the negligence Koch has shown in maintaining the pipeline which crosses my property, their failure to maintain the area gives me great cause for concern that they are also not checking the integrity of the pipeline which could be a hazard to my family and neighbors, based upon several events of escaping gas and explosions that I have heard of in recent years.

Further Affiant sayeth not."

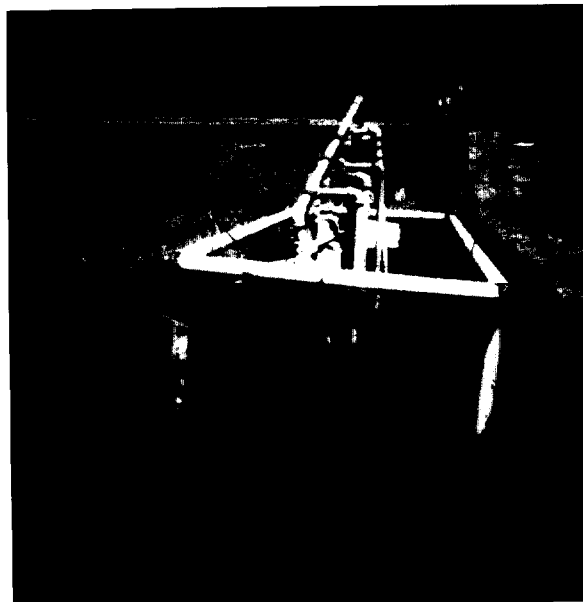
John Freeman
John Freeman

Sworn to and subscribed before me on this 24th day of September, 2001.

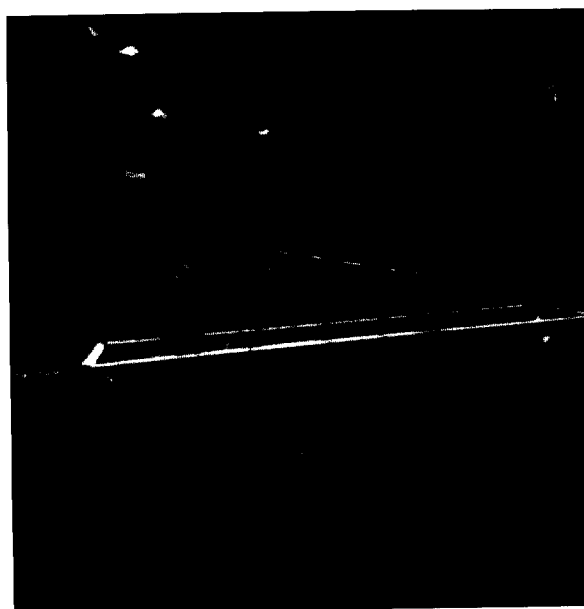


Charla Ward
Notary Public in and for
the State of Texas

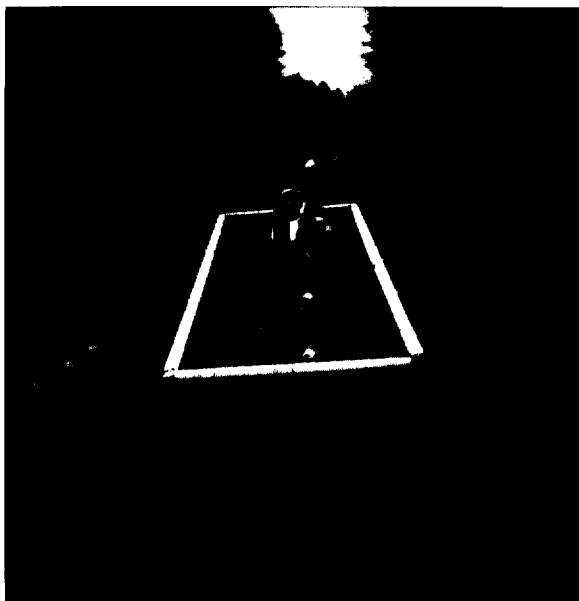
PICTURE #1



PICTURE #2



PICTURE #3



PICTURE #4



PICTURE #5



3 posts

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[Koch News Resource](#) [About Koch](#) [Koch in the Community](#) [Koch and the Environment](#) [Koch Careers](#)



You Know Us Better Than You Think™

[General Overview](#)

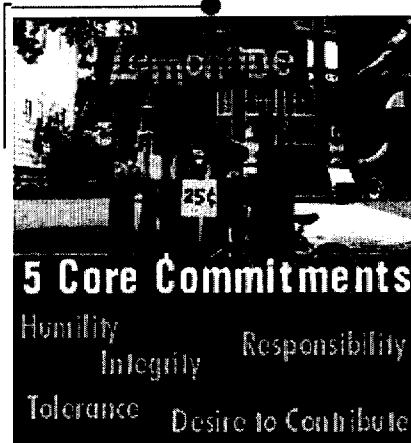
[History](#)

[Philosophy](#)

[Facts About Koch](#)

Koch Overview Philosophy

[Vision](#) | [Core Commitments](#)
[Incentives & Decision Rights](#) | [Knowledge Systems](#)



At Koch Industries, we have gone beyond the familiar notion of corporate culture to build an operating philosophy and set of values that heavily influence the way we do business. We call this system Market-Based Management®, or MBM®. MBM® is the creation of Charles Koch, chairman and CEO. He, along with others, developed this management philosophy based on market-process economics, the philosophies of science and knowledge, and many years of practical business experience.

MBM® is much more than a set of management tools. It involves a vision of our rapidly changing world, a set of core commitments, and an aim to enhance the potential of each employee.

MBM® stands against the traditional command-and-control approach to corporate governance, with its command hierarchy and incentive systems designed to ensure that orders are followed and the hierarchy preserved. MBM® promotes, by contrast, a spontaneous order of employee-entrepreneurs. These individuals work within a framework of appropriate incentives and decision rights, and create value for customers by applying powerful knowledge systems.

We believe that Market-Based Management® improves company performance by helping people realize their potential. In essence, MBM® helps our employees act like owners.

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Koch Breaking News

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comments@kochind.com

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"Market-Based Management is one of the main sources of Koch Industries' success. We believe that any business can benefit tremendously from the principles outlined in this booklet."

Charles G. Koch
Chairman and CEO,
Koch Industries

"This booklet applies market process theory to the internal operation of the firm in a way that is comprehensible to the layman and useful to the practicing manager."

Jack High
Harvard Business School

"Introduction to Market-Based Management is well-thought-out and right on the money as far as we are concerned."

Joel J. Bleth
President, Pump Systems, Inc.

With a Foreword by
Charles G. Koch,
Chairman and CEO,
Koch Industries

By Wayne Gable and Jerry Ellig
Center for Market Processes

Center for Market Processes
4084 University Drive, Fairfax, VA 22030

\$5.00

DM00020

DEPOSITION
EXHIBIT
30 Mills
Jan 10-15 97

About Charles C. Koch

Charles G. Koch has served since 1967 as chairman and CEO of Koch Industries, Inc., a \$20 billion petroleum, chemical, agricultural, and financial services company based in Wichita, Kansas. For the past 25 years, he has worked to improve Koch Industries' management systems by incorporating insights from economics, philosophy, history, psychology, and other disciplines. In 1991, Koch first began describing his management philosophy as "market-based management," and Koch Industries is currently working to develop and apply further the basic market-based management framework to its various businesses.

About the Authors

From 1991 to 1993, Dr. Wayne Gable was managing director for federal affairs and management research at Koch Industries, where his duties included helping to apply market process concepts to the development of management systems. In 1993, he became president of the Center for Market Processes, which has launched a major program to help organizations understand market-based management and develop their own market-based management systems.

Dr. Jerry Ellig, a professor at George Mason University's Program on Social and Organizational Learning, spent part of 1992 and 1993 at the Koch Management Center in Wichita, Kansas, where he researched market-based management ideas and helped develop programs for teaching market process analysis to upper and middle managers. Ellig teaches graduate courses at George Mason University on Market-Based Management and Economic Regulation.

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FOREWORD

Twenty-five years ago, Koch Industries was a small company compared to what we are today. We had fewer than 700 employees, about 1,000 miles of pipeline, and operations focused on Kansas and Oklahoma. Since then, we've established a consistent record of profitable growth significantly above the industry average. We now have approximately 13,000 employees, our pipeline network exceeds 35,000 miles, and our revenues have grown a hundred-fold. We handle several million barrels of hydrocarbons daily, and we have operations in several countries around the world.

Because we've had consistently strong performance over the years, many people have looked at Koch Industries and asked, "How did they do it?" They found that a lot of the usual explanations fail to account for our success. We did not perform better because we had better assets than the competition. In fact, 25 years ago Koch's assets were quite modest compared to many of our competitors. Nor was it because we were smarter than our competitors; if anything, the bigger oil companies' well-known names gave them an edge in attracting people with the greatest potential. We are convinced that Koch Industries' success stems primarily from our management philosophy, which we call "market-based management."

I have personally practiced this philosophy for the past 25 years at Koch Industries. For much of this time the philosophy was more implicit—guiding my business decisions and those in

which I was directly involved. The business and management decisions in which I was not directly involved were often market-based as well, but more through our shared values, culture and business analysis techniques than through a well-articulated management philosophy.

Then, several years ago, we recognized that in order for Koch Industries to continue to succeed we needed to take full advantage of this powerful approach to management. Our entire management team, and eventually our entire organization, needed to understand the framework of market-based management and strive to operate within it. We therefore undertook an initiative with three complementary objectives:

- (1) to articulate the conceptual framework and principles of market-based management in a manner that could be understood by the entire organization,
- (2) to educate Koch management and eventually the entire organization about these concepts and philosophies, and
- (3) to examine all facets of Koch Industries—our values, organizational structure, incentive systems, and other practices—to ensure that each was consistent with the principles of market-based management.

We have made good progress toward the first objective, and this booklet covers most of the principles we believe are important. We have not progressed as far toward the second and third objectives, but where we have applied the framework the results have been powerful enough to convince us we are on the right path.

Our experience has shown that market-based management is a framework within which we can analyze, and even improve upon, other management concepts such as Total Quality Management and Re-Engineering. By testing these ideas and programs against the principles of market-based management, we are better able to discern which parts truly add value and then apply

them in a manner that is consistent and complementary with our other ongoing efforts. This helps us avoid the “false start” and “flavor of the month” problems that have plagued so many other companies and management approaches.

For Koch Industries—and, I believe, for most businesses—constant rethinking and improvement are now more important than ever. The entire business world faces a revolution that will redefine the role of managers, companies, and entire industries. Developments of new technology and changes in consumer desires have always meant change for corporations, but the change occurring today is more fundamental, more rapid, and potentially more devastating than at any time since the industrial revolution. American industry must now deal with massive increases in regulation and other government-imposed burdens. In addition, computer and telecommunications technology have created an explosion of information available to consumers and a wide variety of new means for satisfying consumer desires. This information explosion has redefined the products and services customers want and the forms in which they want them.

Nor is this unprecedented scope and rate of change limited to the information technology industry. America's most traditional industries—from automobiles, to steel production, to retailing—are experiencing it, and there is no end in sight. Business firms must respond more rapidly than ever to changing customer values and to the rapid innovations of competitors.

This kind of rapid response requires new ways of anticipating, discovering and communicating customer desires to everyone in the organization, from the sales force to the accounting staff. Firms also need improved ways of mobilizing everyone's talents, abilities, and knowledge to serve the customer better. These needs require us to constantly redefine the way work is done. It is no longer enough for employees to come to work every day and

work hard at assigned tasks; each day, each person needs to ascertain what he or she can do that creates the most value for customers. In the new environment, only the best managed companies will be able to survive and thrive.

At Koch Industries, we believe market-based management provides a framework that better enables us to meet these requirements. We strive to improve our approach by further educating ourselves about market concepts and by developing market-based solutions to problems common to all organizations. The co-authors of this booklet have both played a role in helping us develop our market-based management ideas. They and other researchers at the Center for Market Processes are well suited to develop further and communicate market-based management to a wider audience in business, nonprofit institutions, and academia.

The power of using the market system as a model for management systems has been only partially tapped, even by companies like ours that have been working on it for many years. I believe there are tremendous opportunities to develop and apply market-based management, and I hope this booklet will generate a greater understanding of the concepts involved. The challenge to improve has never been greater than in today's competitive environment. And while the exact solution is different for each organization, our experience indicates that market-based management is an excellent framework for anyone working to meet that challenge.

— Charles G. Koch
Chairman and CEO, Koch Industries
Wichita, Kansas

WHY "MARKET-BASED" MANAGEMENT?

The past decade has witnessed a dramatic change in both the business world and our broader society. From the Soviet Union to IBM, massive institutions that seemed permanent stumble—or even crumble—in the face of constantly changing political forces, business conditions and information technology.¹

Now more than ever, business managers must struggle to coordinate the knowledge and decisions of tens of thousands of employees from all walks of life. Traditionally, many people have thought that business coordination problems could be solved by hiring better brains at the top of the organization. These "experts" would carefully analyze the company's situation and prepare detailed plans for everyone to implement. This type of solution rests on a boundless optimism that superior minds can foresee every major contingency and find a course of action that is best for all.

In company after company, this approach has failed miserably. It has failed not because business managers were inept or corrupt, but because they overlooked a fundamental reality: the knowledge needed for sensible business decisions is inherently dispersed among many people, and much of it cannot be

¹The authors have spent several years discussing market-based management with, and learning from, Charles Koch, Richard Fink, and Paul Brooks at Koch Industries. We wish to acknowledge the major role played by them in developing the concepts and tools of market-based management, including much of the material covered in this booklet.

²For a sweeping analysis of these changes, see Richard McKenzie and Dwight Lee, *Quicksilver Capital* (New York: The Free Press, 1991).

communicated to a central location for use by "experts." As a result, attempts to centrally plan a complex organization fail when confronted by competing firms that develop better ways to mobilize the knowledge of their people.

But how can an organization tap the knowledge and coordinate the decisions of thousands of employees, if not through command-and-control management?

Contemporary political and economic events suggest an answer. Most economists recognize that the Soviet and Eastern European economies failed because a command-and-control system cannot coordinate the millions of economic decisions needed to produce adequate amounts of consumer goods, even simple ones like bread and shoes.¹ In other words, centralized planning of national economies failed for the same reasons that authoritarian business strategies failed: both approaches overlook the severe limitations to any individual's knowledge.² While executives are beginning to realize this fact, most corporations still look much more like centrally planned economies than market systems.

Centrally planned economies suffer from what Nobel prize-winning economist Friedrich Hayek called the "Fatal Conceit."³ This conceit is the belief that leaders or technical experts know what is best for everyone, and that they can effectively manage society while ignoring what most individuals in society actually know and think. Whenever this philosophy has been tried in practice, it has led to disaster, because no person or committee

can have all of the knowledge needed to plan a complex society. The conceit is indeed fatal, because centralized economic planning condemns most individuals in society to poverty, greater risk of disease, shorter life spans, and less fulfilling lives.

Free societies, on the other hand, have produced the greatest increases in living standards in the history of humanity, because free markets allow individuals to act on their own dispersed knowledge. For striking examples, contrast Hong Kong and the People's Republic of China, or West and East Germany, as shown in the accompanying table on page 8. In both cases, the people share a common history and similar ethnic backgrounds; the principal difference is the economic system. For years, people risked their lives escaping from East to West Germany, and from China to Hong Kong, in search of a better life. These examples demonstrate the superiority of market-oriented systems.

Historical experience shows that market economies, which rely on the dispersed knowledge and independent judgment of numerous consumers and producers, consistently provide a dramatically higher quality of life than centrally planned economies. Given that reality, it makes sense to examine how market economies coordinate human activity, in order to glean lessons for improving business management. Unfortunately, many analysts in business and academia resist this approach, out of a belief that market concepts apply only "out there," beyond the boundaries of the firm. In this view, the principles of a free society apply in the external market, but the firm's internal affairs are the province of brilliant planners making command decisions.

We believe that this point of view misses several elements essential to understanding organizations. The belief that market principles apply only outside the firm resembles the belief that market principles work in international trade, but not for a national economy. The Soviet experience readily calls this claim into

¹Don Lavoie, *National Economic Planning: What is Left?* (Cambridge, MA: Ballinger Publishing, 1985); Peter Boettke, *Why Perestroika Failed* (London: Routledge, 1992).

²Jerry Ellig and Don Lavoie, "Governments, Firms, and the Impossibility of Central Planning," in Paul Foss (ed.), *Introduction to Organization Theory* (Oslo: Norwegian University Press, forthcoming).

³Friedrich Hayek, *The Fatal Conceit* (Chicago: University of Chicago Press, 1990)

FREEDOM WORKS

For years, people fled from East to West Germany, and from the People's Republic of China to Hong Kong, in search of both freedom and prosperity. In both cases, people sought to escape the results of a command-based society in order to enjoy the fruits of a more market-based system. The data below show dramatic differences in physical well-being in countries that shared virtually identical cultures, educational levels, and ethnic heritages before adopting different economic systems. Over time, greater reliance on free markets in Hong Kong and West Germany produced huge differences in human well-being. Not only were living standards dramatically higher in the two market-oriented cases, but less measurable aspects of human well-being, such as individual freedom and human rights, were clearly far more desirable as well. Markets and individual freedom made a profound difference in economic and social well-being.

	Hong Kong	People's Republic of China	West Germany	East Germany
GDP per capita (1988)	\$9,613	\$301	\$19,743	\$5,256
Number of people per*:				
-Telephone	2.2	149.8	1.6	4.3
-Television	4.2	100.7	2.4	5.8
-Car	29.8	1,093.3	2.2	4.8
Life Expectancy:				
-Women	79	71	78	76
-Men	73	68	72	70

Source: *The Economist Book of Vital World Statistics* (Times Books, 1990).

*These statistics do not adjust for product quality, which is much higher in West Germany and Hong Kong than in East Germany or China.

question. The problem with formerly socialist economies was not that they refrained from external trade, but that they failed to implement market principles *internally*. Similarly, we believe firms that fail to learn and adapt market principles internally will one day find themselves distant competitors to firms that do.

The experience of Koch Industries, a firm with which we are quite familiar, shows the power of a more market-based approach. A small crude oil gathering company 25 years ago, Koch's current annual revenues—around \$20 billion—rank behind only Cargill's among privately held American companies. During the past few years, while the major oil companies laid off thousands of workers, Koch Industries was one of the few large companies in this industry to expand.

Koch has also pioneered attempts to turn market principles into a management philosophy. Throughout this booklet, we will employ Koch Industries as a case study in market-based management. Koch's executives would be the first to agree that their ideas are not the last word on the subject, but this company provides the best example we know of a large company that has tried to implement market-based management as a consistent framework.⁶ We hope these examples will pique the interest of executives in other companies who are looking for innovative ways to mobilize each employee's unique knowledge and abilities.

⁶See also Tyler Cowen and Jerry Ellig, "Market-Based Management at Koch Industries," Working Papers in Market-Based Management, Center for Market Processes (June 24, 1993).

WHY IS MARKET-BASED MANAGEMENT DIFFERENT?

On the surface, market-based management shares some similarities with total quality management, just-in-time inventory control, and other currently popular management practices. Like market-based management, these programs help organizations tap the dispersed and tacit knowledge of many employees. Tapping the creativity and knowledge spread throughout an organization is essential, yet extremely difficult in practice, as indicated by the growing number of companies that have abandoned total quality management in frustration.

Market-based management gives us more than a list of additional management tools. It provides an overall framework—a “paradigm” for understanding organizational problems. The market-based management framework helps us examine and evaluate the tools of just-in-time inventory, total quality management, and other ideas for improving organizational performance.

The paradigm underlying market-based management is a method of understanding human action and interaction called “market process analysis.” Market process analysis helps us understand how free societies organize themselves to allow people to live and work in harmony, while increasing the well-being of the entire society. The market process allows vast amounts of human activity to be undertaken independently, yet coordinated with the activities of others. This coordination, referred to by Adam Smith in the *Wealth of Nations* as the “invisible hand” and by Nobel laureate F.A. Hayek as “spontaneous order,” is responsible for the vast increase in living standards that has

occurred in many societies since the industrial revolution. This increase in human well-being resulted from the unleashing of individual initiative rather than from the actions of governments. The market system enabled people to create and distribute wealth on a scale never imagined by previous generations.⁷

A business firm is not just a piece of society, but a mini-society in its own right. Like societies that adopt market-based rules and cultures, organizations can vastly increase their effectiveness by using the market system as a guide for redesigning their own systems. In fact, during the past several decades, many of the most forward-looking management thinkers have de-emphasized hierarchy, authority, and other “command-oriented” management techniques that became common during the first half of this century. Early management thinkers tended to follow the command-oriented “scientific management” school of thought championed by Frederick Taylor.⁸ The similarities between the Taylorist approach to management and Soviet-style “economic planning” are uncanny, and they are not coincidental. Both approaches arise from the same framework: a framework that can understand order and coordination only as the deliberate product of some planner’s design. As a result, both Taylorism and centralized economic planning depend on the ability of a central authority, whether economy-wide or organization-wide, to accumulate, process, and act on vast amounts of knowledge.⁹ And experience has proven both wrong.

⁷Adam Smith, *An Inquiry Into the Nature and Causes of the Wealth of Nations* (Chicago: University of Chicago Press, 1976 [1904]); Friedrich Hayek, *Law, Legislation, and Liberty* (Chicago: University of Chicago Press, 1979).

⁸Frederick W. Taylor, *Principles of Scientific Management* (New York: Norton, 1911).
⁹In fact, two of the Soviet Union’s “founding fathers,” Lenin and Trotsky, admired the Taylorist system and saw centralized economic planning as a means of making all of society run as smoothly as a factory. See Peter Boettke, *The Political Economy of Soviet Socialism* (Boston: Kluwer Academic Publishers, 1990), pp. 105–6.

Even the long-time defenders of Soviet-type systems have now declared them a massive failure. It is widely recognized that, no matter how intelligent and well-meaning the "authorities" are, and no matter how sophisticated their planning tools, there is simply no way for a government to "run" an economy. Many recent developments in management theory suggest that the same is true for organizations. Rather than emphasizing authority, hierarchy, management information, and "planning," more and more management thinkers are emphasizing decentralization, empowerment, organizational learning, cross-functional teams, consumer sovereignty, and other concepts that don't fit the "scientific management" mold.

In focusing on these concepts, executives knowingly or unknowingly incorporate key elements of a free society into their corporate cultures, informal rules, organizational structures and incentive systems. We believe there is a discernible evolution away from "scientific" management toward a more effective approach—market-based management. Market-based management is based on a fundamental understanding of how the market system enables a group of people to achieve cooperatively results that far exceed what they could have achieved separately.

To avoid misunderstanding, we should note some misconceptions that often come with the name "market-based management." First, market-based management does not mean a mindless copying of external market practices inside the firm. A key difference between the business firm and our broader society is that the business firm exists to accomplish some specific mission, whereas a free society exists only as a means of allowing individuals to accomplish their own goals. Market-based management focuses on discovering organizational structures, responsibilities, values, and incentives that motivate people to advance a common mission. It does not mean merely turning everyone in the firm loose to do whatever they think will make money.

Second, market-based management does not mean simply being "responsive to the market." In our discussions with business leaders, we frequently hear, "Of course we're market-based; we respond to our customers." Any effective management system should help a firm respond to its customers, but market-based management is much more than responding to customers.

Market-based management is also different from various proposals for "industrial democracy" and "participative management." It shares with these approaches a skepticism of centralized management, but offers different solutions to the managerial coordination problem. The goal of many democratic and participative systems is to give every employee a voice in major decisions, either directly or through elected representatives. This approach relies on everyone being well enough informed to contribute to most decisions—a situation just as unlikely as one person having sufficient knowledge to make most decisions. Market-based management, in contrast, seeks to divide up decisionmaking, so that the person or team with the requisite knowledge and the right incentives makes each decision and bears ongoing responsibility for the outcome.

Finally, it would be a mistake to identify market-based management merely with the creation of competitive bidding or spot markets inside the firm. This misconception stems from a view of markets as nothing more than a sea of rivalrous, atomistic competition.¹⁰ In reality, markets are a complex blend of competition and cooperation. Likewise, a market-based firm should promote cooperation while channeling competition into activities that actually promote the common mission.¹¹

¹⁰ The overemphasis on "competitive" relative to "cooperative" forces in the market process, and the analytical errors that result, are examined by Richard Fink, *Price Theory and Pricing Practice* (Routledge, forthcoming).

¹¹ We disagree with the notion that the essence of the firm is the substitution of command for market relationships. Readers concerned about this issue should see G. B. Richardson, "The Organisation of Industry," in Richardson, *Information and Investment* (Oxford: Clarendon Press, 1990).

SIX KEY SYSTEMS IN MARKETS AND ORGANIZATIONS

The market-based approach to management draws heavily on lessons learned from market process analysis. Markets facilitate economic growth and social progress through a highly complex process. To provide a workable framework for understanding the implications for organizations, we have focused on six key elements of the market system: division of labor, property rights, rules of just conduct, the price system, free flow of ideas, and market incentives.

Within the firm, each of these concepts has a parallel element in management practice, as illustrated by the table on page 15. The *Mission System* helps identify and keep everyone focused on the things that this particular organization does particularly well. A well-defined system of *Roles and Responsibilities* functions like property rights in the market. They link independent judgment with proper accountability, both for business units and for individuals. An organization's *Values and Culture* establish a framework that helps guide people in making decisions, just as laws and cultural norms guide behavior in the broader society. In the marketplace, the price system summarizes a tremendous amount of knowledge about the relative scarcity and demand for resources; similarly inside the firm, *Internal Markets* give people access to crucial information that they have no other way of obtaining. People also acquire critical information through disclosure, and *Open Communication* is as critical inside the firm as in a free society. Finally, in a free market, profit and loss indicate value added and provide incentives for improvement; the firm's

Compensation and Motivation system should provide similar incentives.

When all six of these systems function well in a society, the results are truly dramatic. Societies that have these six systems have achieved tremendous increases in human well-being by successfully utilizing the knowledge that is spread out among all

Six Key Systems in Market Economies and Organizations	
Market Economy	Organization
Division of Labor	Mission System
Property Rights	Roles and Responsibilities
Rules of Just Conduct	Values and Culture
Price System	Internal Markets
Free Flow of Ideas	Open Communication
Market Incentives	Compensation and Motivation

of their people. We can refer to these results broadly as "social learning." Similarly, when the analogous systems function well inside the firm, "organizational learning" occurs; the firm finds more effective ways to mobilize the knowledge of its people in pursuit of its mission.

More and more organizations are realizing that, regardless of what businesses they are in, they must also be in the "knowledge business." They must focus on generating and mobilizing the knowledge of their employees.¹² To survive and thrive in today's

¹²Peter Senge, *The Fifth Discipline* (New York: Doubleday, 1990).

business environment, an organization must be able to learn, adapt, and improve itself continuously. If it does not, its competitors will soon leave it far behind. While each of the six systems is critical for the market-based organization to develop and improve, managers should remember that the systems are highly interrelated. Attempts to improve organizational performance by focusing on only one system probably won't work.

DIVISION OF LABOR AND THE MISSION SYSTEM

Free societies generate wealth by facilitating an ever more complex division of labor and knowledge. Such specialization enhances productivity, because it allows each person to focus on the activities that create the most value at the least cost. A firm's mission system helps identify the activities in which it should specialize for maximum long-term profitability. In addition, when a firm understands its own "core competencies," it then has a much better idea of how its various divisions or profit centers should interact in order to accomplish its overall mission. To see in greater detail how an organization can identify its core competencies, we need to see how the division of labor works in a market economy.

Division of Labor and Comparative Advantage

Division of labor increases productivity by allowing each person or firm to exploit a "comparative advantage." To understand the role of comparative advantage in creating wealth for society, think about two farmers: an Idaho potato grower and a Louisiana rice grower. They can produce more potatoes and rice if each specializes in one crop than if each tries to be self-sufficient in both crops. To see why, imagine what would happen if the Idaho

farmer tried to grow rice. Because the Idaho climate is better for potatoes, the farmer would give up a lot of potatoes to grow just a little rice. Idaho-grown rice would be very expensive, because customers would have to offer the farmer a high price for rice to make up for the lost income from potatoes. Similarly, the Louisiana farmer would give up a lot of rice in order to grow just a few potatoes in a swampy rice paddy. Potatoes grown in Louisiana rice paddies would be expensive, because it would take a very high potato price to replace the income that the farmer could have earned from growing rice.

In economist's jargon, the Idaho farmer has a "comparative advantage" in growing potatoes, and the Louisiana farmer has a comparative advantage in growing rice. Both farmers are better off if they grow the crop for which they have a comparative advantage, then trade for the other things they need. The rice farmer gets cheaper potatoes, and the potato farmer gets cheaper rice.

David Ricardo, a 19th-century economist, first developed the concept of comparative advantage to explain international trade. In reality, the principle is much broader than that, because it explains why different people specialize in producing some things and then buy whatever else they need from other people. An auto worker who buys vegetables at the grocery store, visits the doctor for a prescription, and rents videos for entertainment is practicing the principle of comparative advantage.

People and organizations can have comparative advantages for many reasons besides climate and soil. Individuals are born with different types of abilities, and so there would be gains from specialization even if we all lived in the same climate. Experience and education can generate comparative advantage, as people invest in developing skills that let them do new things with less time and effort.

While the specialization of different people in different activities is good for the people themselves, it is also good for society

in general. If lots of Idaho farmers "wasted" resources growing rice and Louisiana farmers wasted resources growing potatoes, all of society would suffer the consequences. As a society, we should want farmers to grow the things they are best suited to grow, so we can use our limited resources to produce other things we need. Societies with market systems out-perform societies run by command, in part because the market system applies the principle of division of labor across the entire economy.

The Comparative Advantage of a Firm

Organizations too can possess comparative advantages, because groups of people can jointly develop capabilities to do certain things particularly well. Wal-Mart, for example, has excelled by developing superior communication and transportation links between individual stores, warehouses, and suppliers; the company has a comparative advantage in getting customers the merchandise they want quickly and efficiently.¹³ But having a comparative advantage in something also implies comparative disadvantages in other activities. If Wal-Mart stopped running retail stores and went into the oil drilling industry, it would probably lose money, because its communication and transportation skills might not be very useful in oil drilling. Thus, Wal-Mart and other companies have a strong incentive to concentrate their efforts in those areas in which they can contribute most to society.

A firm, like an individual, makes the most profits over the long term when it specializes in activities that create the most value for customers at the least cost. The firm's mission system helps promote long-term profitability by identifying the orga-

¹³George Stalk, Philip Evans, and Lawrence Shulman, "Competing on Capabilities: The New Rules of Corporate Strategy," *Harvard Business Review* (March-April 1992).

nization's comparative advantages, enabling each employee to focus on enhancing them, and giving employees a better means of measuring whether their efforts have been successful.

As the Wal-Mart example suggests, the process of developing and enhancing comparative advantage is complex. Physical assets and technical skills are important, but equally important are systems that enable everyone in the organization to combine their skills and abilities to deliver value in ways that competitors cannot match. Organization, values, and communication all play a crucial role in the creation of comparative advantage. The firm's mission, therefore, should provide a basis for evaluating and improving all of these aspects of the organization.

What happens when a company chooses to specialize in activities in which it doesn't have a comparative advantage? The market system gives it clear feedback in the form of sustained losses. Competitors who *do* have a comparative advantage in the business will emerge, and the errant company will eventually be forced to improve or exit the business. Although this process may sound cruel, it is actually quite humane. A corporation that decides to specialize in a business in which it lacks a comparative advantage is actually wasting resources. The resources available for investment in productive activity are limited, and when a firm uses up more resources than necessary to create a given level of value for consumers, the extra resources it used are gone forever. The additional value they could have provided for consumers will never be seen by anyone.

Koch Industries' Mission System

The concept of comparative advantage has played a large role in guiding business leaders at Koch Industries. One senior executive often comments, "We used to think we were in the oil business; it turned out that we're in the purchasing, transportation,

processing, sales, and trading businesses.” When Koch’s managers began to view the company’s expertise as transportation and processing, they started doing a number of things differently. Koch exited the retail gasoline business years ago, because it believed that retailing requires expertise quite different from that required in other businesses. Similarly, the company does a very limited amount of oil exploration and production—and only when these activities clearly complement the core businesses.

Koch Industries has developed a methodology for discovering its comparative advantages, organizing activities, and measuring success. The Koch “mission system” is an ongoing process in which employees systematically improve their understanding of the firm’s capabilities and markets, define goals, plan ways to achieve the goals, and monitor progress. Many firms have mission statements that are intended to inspire employees to work toward common goals. At Koch, the mission statement is used more for strategic planning than for motivational inspiration. A mission statement is just one aspect of the mission system, and it continually changes as employees’ understanding of the firm’s competitive position changes.

Koch Industries divides its mission system into four key elements. The first element, **Understanding the Business**, involves deciding what is realistically possible given the nature of the markets, the competition, the firm’s resources, and its capabilities. This understanding comes from knowing the business, its history, relevant economic theory, management tools, and the firm’s competitive advantage.¹⁴ Relevant questions that help refine this understanding include:

- Who are the key customers in this industry?

- Which of our activities create value for which customers are willing to pay, and which do not?
- What criteria guide customer purchasing decisions?
- How do we rate on these criteria, compared to the competition?
- What additional services could we provide that the customer would be willing to buy?
- What influences prices in this industry?
- What are the “best practices” employed by anyone in this industry?
- What are the key activities necessary for success in this business?
- How will emerging industry trends and changing technology alter the ways our customers create value, and the ways we can create value for them?
- Which activities are most profitable, and which are unprofitable?
- Why are we making profits or losses?
- How can we improve profits or eliminate losses?

The second element, deciding **What to Do**, is fairly self-explanatory. Many company missions are too general, emphasizing factors like growth or improvement without an understanding of whether they are desirable or feasible, and without specifying the most profitable ways to target the firm’s efforts. To create a mission, a business must really understand where it can create the most value at the least cost. The mission must also be realistic and specific enough that the business can measure its performance against the resulting price, quality, and service goals.

Planning **How to Do It** involves enunciating the concrete steps to accomplish the goals. Without this aspect of the mission

¹⁴In this type of analysis, Koch executives have been influenced by Michael Porter, *Competitive Advantage* (New York: The Free Press, 1985), and Ludwig von Mises, *Human Action*, 3d Revised ed. (Chicago: Contemporary books, 1966).

system, the mission is just empty words that do nothing to help coordinate activities. The planning process should include strategies to advance the mission for each part of the business, including each division, product, facility, operation, and function.

The fourth element, **Monitoring Progress**, is extremely easy to do poorly but extremely important to do well. For each goal, businesses and individuals need to develop measures of progress in advancing the mission. That imperative places a premium on measuring results, not activities, and on defining quality before measuring quantity. In addition, all measures need to be related to the broad goal of providing the most value at the least cost. Business history is full of examples of firms that achieved poor results—or even failed—because they measured the wrong things. It is all too easy to measure the things that are easily measurable, rather than measuring the things that actually provide guidance in advancing the mission.

Paradoxically, the quest for meaningful measures may be most important in businesses where it is the most difficult. This is true because a thorough search for measures will often lead to a greater understanding of the business even if it fails to yield perfect measures. The more difficult a business is to define and measure, the more important a keen understanding of that business becomes.

The monitoring process must provide feedback that is accurate, timely, and in a form that can guide actions. In particular, businesses and individuals should be evaluated on measures that they can actually affect. A welder in an auto plant, for example, should be evaluated primarily on her activities that have the strongest impact on profitability. All too often, people like the welder are implicitly measured and rewarded according to criteria they cannot directly affect, such as the gross profit margin on cars or the total volume of cars sold, with little

SUMMARY: DIVISION OF LABOR AND THE MISSION SYSTEM

COMMAND	SOCIETY	ORGANIZATION
MARKET-BASED	<p>Individuals and organizations develop mission to create value by focusing on comparative advantage.</p> <p>Individuals rewarded for helping organization satisfy its customers.</p> <p>Firms developing comparative advantage and pleasing customers earn long-term profits.</p>	<p>Individuals and organizations develop mission to create value by focusing on comparative advantage.</p> <p>Individuals rewarded for helping organization satisfy its customers.</p> <p>Firms developing comparative advantage and pleasing customers earn long-term profits.</p>

emphasis on individual performance. Measurement systems should evaluate contributions to both local and organization-wide performance, and rewards should be based on clearly understood criteria.

Earlier we described Adam Smith's concept of the "invisible hand," a metaphor for the way that people mutually adjust their decisions and activities to fit with those of others. It is useful to think of an organization's mission system as a "visible hand," which gives employees important information they need to work as a team in accomplishing common goals. Through a well-developed and well-defined mission system, an organization can achieve a harmony of interests among its employees very similar to the harmony of interests that exists in a market economy. This requires educating all employees on the organization's mission, helping them understand how it is relevant to them, and encouraging them to develop personal missions that support the common mission. Ultimately, each person's mission should answer the question, "What can I do to promote long-term profitability, consistent with the firm's overall mission?"

PROPERTY RIGHTS, ROLES, AND RESPONSIBILITIES

In a market economy, the institution of private property plays a key role in promoting productive activity. Private property has three fundamental characteristics: individuals can decide how to use their property, they can earn income from it, and they can freely sell their property to someone else. Each of these aspects

has a significant social role. Independent judgment harnesses the specific knowledge of time, place, and circumstances that no planner (or CEO!) can possibly possess. Income from private property gives the owner continuous feedback on how well he is satisfying customers. And the sale of property capitalizes the value of future earnings, so that people take into account the long-term consequences of their decisions.¹⁵

Independent Judgment Harnesses Knowledge

Every social system provides some means of organizing resources to satisfy human wants and needs. No mind or committee can possibly know the intensity of everyone's desires for various goods and services or all of the possible ways of providing them. But each person in society has important knowledge, especially about his own desires and abilities. Private property harnesses this knowledge by allowing people to make independent decisions about the uses to which resources will be put.

Voluntary trade involves not just an exchange of money and property, but an exchange of knowledge. For example, someone with 50 cents buys an apple because he values the apple more than the 50 cents. By paying the 50 cents, that person is declaring to the store owner, "This apple is more valuable to me than to you, and the 50 cents is more valuable to you than to me." Conversely, the store owner makes the trade if he values the 50 cents more than the apple; he is telling the customer, "I agree; the apple is more valuable to you, and the 50 cents is more valuable to me." If customers could just walk into stores and take apples without paying for them, we would never know who placed more value on the apple. Voluntary exchange ensures that resources do not change hands unless the person acquiring them values them more than the person giving them

¹⁵Randy E. Barnett, "The Function of Several Property and Freedom of Contract," *Social Philosophy & Policy* (1992), pp. 62-94.

up.¹⁶ Taken as a whole, the system of voluntary exchange enables millions of transactions of this type to generate knowledge about the most valuable use of resources in society.

Profit and Loss Provide Feedback

Voluntary exchange and private property provide strong incentives for businesses to serve consumers and strong feedback on the quality of service. In a free exchange, each person gains control over more valuable resources by giving the other something he wants more. This illustrates a fundamental principle of economics: to profit in a truly free market, firms have to find ways of delivering more value to customers while using fewer resources than their competitors. Once again, Adam Smith's "invisible hand" leads the profit seeker to act in ways that benefit society. "Total quality" gurus like Deming and Juran, who speak of defining quality in terms of customer desires, have rediscovered the "invisible hand." In a free market system, profits are the rewards for success in serving customers.

Profits earned in the marketplace signify that an enterprise has made a valuable contribution to society. Profits also give entrepreneurs with good judgment control over more resources so they can try creating value on an even larger scale. On the other hand, losses indicate that the firm has taken important resources and diminished their value. Losses also help separate people with poor judgment from the control of resources. One of the market's greatest strengths is its ability to match greater control over society's resources with those who have the best ability to make decisions. For centuries, social thinkers have misunderstood the role of profit in the market, yet no one has

¹⁶ This value judgment is, of course, made in practice *before* the buyer consumes the product. The buyer may later regret his decision, but at the time of purchase the apple was worth more to him than the price.

been able to design a social planning system which even comes close to performing as well.

Purchase and Sale Capitalize Future Effects

To see how the right to sell property makes people accountable for the long-term effects of their actions, think about contemporary situations where property is not private, and so people cannot profit from preserving the value of resources. The air is regarded as public property, and the government feels compelled to regulate air pollution precisely because there is no owner who bears responsibility for keeping the air clean. Similarly, many American rivers became choked with pollution because *no one owned them*; no one had a strong enough incentive to preserve their future value by preventing pollution. Ecologists call this type of situation "the tragedy of the commons," because when a resource is considered public or "common" property, no one has a strong incentive to conserve and protect it.

Private ownership, on the other hand, creates strong incentives to preserve the value of resources. In Scotland, for example, the water in privately owned streams is crystal clear. Why? Because the stream owners have a legal right to limit water pollution, and they do so in order to protect the revenues they earn from selling fishing licenses.

If the environmental examples sound too far-fetched, think of the different habits we often associate with homeowners and renters. Homeowners plant trees, install roofs that will last for 20 years, and buy long-lived, heavy appliances in part because these investments all increase the value of the home when it is sold. Renters, on the other hand, often have to place a deposit up front to cover any damage they might do to the property. Without the deposit, renters would have less incentive to care about the condition of the property after they leave; the deposit is a way of inducing them to act more like owners.

It is important to understand that, in describing the important roles played by the institution of private property and the system of profit and loss, we are not claiming that all profits are socially “deserved.” Profits promote a harmony of interests between the individual and society in free markets that have not been politicized. But companies can also make huge profits when legal or regulatory barriers prevent effective competition, as in the case of a government-granted cartel or monopoly. This allows the corporation to replace market competition—producing greater value using fewer resources—with what might be called “political” competition. Individuals or companies can also profit through government subsidies. Here the value judgments (and resources) of consumers are replaced by the value judgments of the government and the resources of the taxpayer. In these cases, the profit-and-loss system is not allowed to function effectively.

Profits earned by creating value for consumers stem from the creation of wealth for society. Profits acquired through government stem from *redistribution* of wealth that someone else has created. Historian Franz Oppenheimer referred to the second strategy as the “political means” of profit.¹⁷ Oppenheimer distinguished the political means from what he called the “economic means”—creating greater value for customers while using fewer resources than competitors. The possibility of profiting from the political means, and the extensive resources devoted to this strategy, make it difficult for us simply to look at the most profitable companies and conclude that they are necessarily superior to all others at creating value for society.

¹⁷ Franz Oppenheimer, *The State* (New York: Vanguard Press, 1914), pp. 24–27.

Implications for Business Units

To devise a market-based organizational structure, executives need to understand the beneficial characteristics of private property. The goal is not simply to *copy* the external market; we do not necessarily advocate making all workers buy their own tools or letting middle managers sublease their offices to outside customers. Rather, the goal is to understand the crucial functions played by private property in a market economy, and then allocate rights and responsibilities in ways that harness independent judgment, provide continuous feedback, and capitalize the future impact of current decisions.

At the business unit level, a firm can facilitate profit-and-loss calculation through the creation of profit centers. A profit center is a definable unit within a business, created from any set of activities for which financial statements can be prepared. Unlike independent firms, however, profit centers operate within the context of a larger organization. It would be a mistake simply to turn profit centers loose to do whatever makes profits, for then there is little reason for having them in the same firm. But how, then, does a company decide when to create a distinct profit center within the larger organization and when to spin it off as a totally separate entity?

Koch Industries tries to answer this question by evaluating profit centers not just on their own profitability, but also on the external benefits or costs they create for other profit centers. A business engaged in activities in which the company has a comparative advantage naturally falls within the company’s “core.” Other, noncore businesses are evaluated based on their positive or negative impact on the core businesses. For example, Koch retains some profit centers not because of their inherent profitability for the company, but because of their positive net impact on what Koch views as its core businesses. Similarly, parts of the

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company that are not profit centers at all, such as accounting and other "support" groups, are evaluated primarily on the value they create for the profit centers. This type of structure makes evaluation more difficult for Koch businesses than for independent firms in the marketplace. But complex and decentralized evaluation procedures are crucial for reaping the benefits of teamwork across multiple profit centers.

Implications for Individuals

Profit centers make separate pieces of the organization accountable for their actions, but to reap the full benefits of a market-based system, accountability must extend to the level of the individual. For individuals, well-defined roles and responsibilities inside the firm play a role similar to that of private property, and for many of the same reasons. Like private property, roles and responsibilities define the area within which a person or team is free to utilize local knowledge, make judgments, and bear the consequences.

All too often, things fail to get done in business organizations because everyone thought it was someone else's responsibility. The similarity between this situation and the "tragedy of the commons" is obvious. In effect, the activity in question was turned into public property. Since no one "owned" it, no one followed up to make sure it was done. Well-defined roles and responsibilities can prevent this type of problem by assigning a kind of "ownership" for every activity, action, and result.

In the free market, profit and loss continually reallocate control over resources to those skillful enough, or lucky enough, to please the customer more effectively than competitors. Like a society, an organization needs some way of assigning and reallocating roles and responsibilities. Koch Industries tries to reallocate roles and responsibilities based on an employee's demonstrated ability to make good decisions and satisfy customer needs.

Each person enters the company with control over a significant asset: his or her own abilities. Employees are expected to think in terms of the company's long-term profit and loss when deciding how to use their time. As people demonstrate sound judgment and good stewardship of corporate resources, they receive expanded authority to commit corporate resources to projects. This authority system applies both to internal resource allocation and external purchase decisions, and it has allowed Koch to abolish centrally approved budgets. In place of command-and-control budgeting, Koch tries to approximate the market's allocation through profits and losses. If a manager makes consistently poor business decisions over time, his authority to make future decisions eventually shrinks.

Well-defined roles should not be confused with detailed job descriptions. Historically, job descriptions in businesses have consisted of task lists. At their worst, these job descriptions have undermined teamwork and productivity—as when a store cashier refuses to sweep the floor because, "It's not in my job description." Roles and responsibilities, on the other hand, continually change as the external market, business mission, and employee's knowledge and capabilities change.

What should a market-based system of roles and responsibilities look like? While it would be impossible to define an exact system for all organizations, we can identify several appropriate characteristics:

1. An individual's roles and responsibilities should be based on the individual's mission, developed within the context of the relevant business unit and overall organizational mission.
2. Roles and responsibilities should be developed with an understanding of the individual's knowledge base and incentive structure. The individual should be allowed to make decisions or take actions which he or she is better qualified to

SUMMARY: PROPERTY RIGHTS, ROLES, AND RESPONSIBILITIES

COMMAND	SOCIETY	ORGANIZATION
MARKET-BASED	<ul style="list-style-type: none"> • Private property rights permit individual choice in use of resources (within legal guidelines) • Income from property (the system of profit and loss) provides continuous feedback • Transferability of property leads to effective stewardship of resources 	<ul style="list-style-type: none"> • Roles and responsibilities define sphere for individual responsibility and autonomy • Employee responsibilities grow or shrink with individual's record of success • Roles and responsibilities change as corporate mission or individual knowledge and skills change

make than anyone in the organization, and his or her compensation should be based on effectiveness in that role.

3. Specific roles and responsibilities should be determined (and changed when necessary) for articulated and well-understood reasons.

4. New situations are likely to arise over time, so there should be a clearly understood process for addressing and resolving questions of overlapping roles or gaps between roles. Incentive compensation should be based on an employee's contribution to working out conflicts in a positive way as well as on working within the current system.

5. Expectations of performance, including the measures to be used, should be communicated and clearly understood.

RULES, VALUES, AND CULTURE

In every society, various written and unwritten rules of just conduct provide guidelines for acceptable behavior. Some societies have rules that reward hard work, innovation, and service to others; other societies have rules that reward indolence, conflict, and power-seeking. It's not hard to predict which of these societies have been more successful in increasing the well-being of their members. Sensible rules also make people's behavior more predictable to others, and this predictability helps all people accomplish their different goals.

Rules that Promote Prosperity

A society's rules of just conduct can be divided into the formal and the informal. Formal rules are written laws, such as those against murder and theft. For these rules to be effective, most people must accept and follow them voluntarily. The gang wars during Prohibition and riots in Los Angeles illustrate what happens when a sizable number of people choose not to accept formal rules of just conduct.

If law-breaking becomes widespread, it is much harder for people to accomplish their goals, because the behavior of other people is too unpredictable. An urban store owner faced with the threat of looters, for example, will try to protect himself from this uncertainty by carrying a smaller stock of merchandise and charging higher prices to pay for a security system. As a result, the threat of looting harms not just the store owner, but all of the customers in the surrounding community.

Beyond the formal rules are informal rules of just conduct. These are the customs, codes of decency, and culture that exist in society. For example, most people try to give accurate directions to strangers who ask for directions. But if a substantial number of people enjoy giving out wrong directions—or just guess at the directions because they don't want to admit that they don't know—travelers find it harder to get to their destinations in a reasonable time. Few places have formal laws about giving directions, but there is an unspoken norm that says we should be honest when someone asks. Similarly, some companies' informal rules of just conduct include honoring their agreements, but others will break agreements if they can get away with it. Adherence to commonly acknowledged business ethics makes us all wealthier by reducing the amount of resources we have to devote to contract negotiation and enforcement.

Over time, a large number of rules and norms have evolved in our society.¹⁸ Concepts like honesty, respect for private property, and keeping one's word play a significant role in advancing our standard of living, because they promote the types of long-term investment and risk-taking that enhance human welfare. A corn farmer, for example, fully plants his acreage because he knows where the boundaries are, and he knows others will respect them. If the boundaries are in dispute on one quarter of the property, he probably will not invest as much time and money in planting that area as he would in the areas where his property rights are certain. If a gang periodically burns his crop or if the government periodically confiscates it, he will invest less time and money in developing that farm. Many people in the modern world, from residents of America's inner cities to inhabitants of war-torn countries, are in a position little better than the farmer beset by bandits—and for similar reasons. Prosperity slips away when the rules of just conduct break

¹⁸Friedrich Hayek, *The Fatal Conceit* (Chicago: University of Chicago Press, 1992).

down, because people lack the predictability needed to make long-term plans and investments.

Just as scientific progress changes our understanding of the physical world, learning and experience gradually change people's ideas about the appropriate rules of just conduct. Formal rules are subject to change by government, of course, but informal rules constantly evolve as well. Customs regarding smoking are a good example. It used to be considered impolite to ask someone to put out a cigarette; now, it's considered impolite to light up without asking if the smoke will bother anyone.

Corporate Values and Culture

Rules defining acceptable behavior make the actions of others in society more predictable and beneficial. Similarly, a company's values and culture can guide employees' actions in ways that advance the common mission. In emphasizing values and culture, we explicitly reject the popular idea that there exists a conflict between what is profitable and what is moral. In society and in organizations, moral principles serve the crucial function of guiding our decisions in ways that promote our long-term welfare. The relevant tradeoff is not what is right versus what is profitable; it is between long-term and short-term profitability. If an organization's moral principles are sound, doing the right thing also enhances profitability over the long term.

For an illustration of rules of just conduct, we turn again to Koch Industries. Some key concepts in Koch's written statement of corporate principles are humility, intellectual honesty, openness, receptiveness to new ideas, treating others with dignity and respect, recognizing and using everyone's unique knowledge and abilities, and instilling a commitment to the common mission.

Of course, any organization can pay lip service to these types of principles, and putting principles on paper but not in practice can seriously damage a corporation's underlying culture. But

when actually followed in practice, principles like these can promote the trust and openness that allow organizations to tap tremendous employee knowledge and creativity. Employees who exhibit humility recognize that they do not have all the answers, and probably never will. Without humility, individual and organizational learning is difficult if not impossible. Intellectual honesty means people admitting what they don't know, acknowledging mistakes, and searching for evidence that contradicts their positions with as much vigor as they search for evidence that confirms their positions.

When principles like these are not followed, a corporate culture develops in which "information is power," and those who collect and hoard key information are rewarded with positions of greater authority. It is easy to see the damage that such a culture can do to an organization that needs to tap and integrate the dispersed knowledge of all its employees. Finding solutions to complex problems is all but impossible if an organization depends on one person collecting the relevant information. A culture of genuine humility and honesty must be established in order to achieve organizational learning and profitability.

The Koch principles may sound like common sense, but they contrast sharply with the informal culture in many organizations. Managers often face strong pressure to appear competent and put a positive spin on every development, even if it was a genuine mistake. When mistakes occur, people often ask, "How can we avoid blame?" instead of asking, "What can we learn?" Edgar Schein, an organizational learning specialist at MIT, has noted that even in organizations that encourage people to learn from mistakes, there is often an unspoken prohibition on making the same mistake more than once.⁹¹ In such an environment, managers may analyze past mistakes, but

⁹¹ Edgar Schein, "How Can Organizations Learn Faster? The Challenge of Fostering the Green Room," *Sloan Management Review* (Winter 1993), pp. 85-92.

SUMMARY: RULES, VALUES, AND CULTURE

COMMAND	SOCIETY	ORGANIZATION
<ul style="list-style-type: none"> • Respect for private property and individual rights • Freedom in dealing with others • Tolerance of alternative views and lifestyles • Respect for individual initiative and entrepreneurship 		<ul style="list-style-type: none"> • Accumulation of power by hoarding key information • Obedience to corporate authority
MARKET-BASED		<ul style="list-style-type: none"> • Respect for others' knowledge and expertise • Intellectual honesty and humility • Openness to new ideas or ways of accomplishing corporate mission • Freedom to question current practices or suggest improvements

the main thing they learn is to avoid activities that carry some risk of repeating a mistake. As a result, people shy away from taking healthy risks, and they lose the opportunity to recognize patterns of events that repeatedly generate the same types of mistakes.

A company's actual values and culture also exercise a heavy influence on managers' attitude toward change. If followed consistently, principles like humility, intellectual honesty, and receptiveness to new ideas encourage people to embrace change as an opportunity for improvement, instead of avoiding it as a threat. Yet in many organizations, people spend a great deal of time and effort resisting change, under the guise of weeding out "unwise" change. Values that promote openness to change are now more important than ever, because in the modern business environment to resist change is virtually to guarantee failure.

THE PRICE SYSTEM AND INTERNAL MARKETS

In a society of independent decision makers, people need some means of coordinating their decisions with those of others. A free society lets millions of individuals simultaneously try to accomplish their various goals. Yet at the same time, people cooperate harmoniously to accomplish their goals better than they could by acting alone. Market prices play a large role in providing both the information and the incentives that make this mutually beneficial activity possible. Guided by

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prices, both business and consumers weigh alternatives and make choices in ways that take other people's plans and desires into account.²⁰

The Power of Prices

The absence of gasoline lines during the Persian Gulf war powerfully demonstrates the price system's ability to promote coordination. When Saddam Hussein invaded Kuwait, a portion of the world's oil supply was temporarily cut off, and many people expected the Gulf war to reduce supply further. With less oil available, it was only sensible for people to conserve. The oil price increase following the invasion accomplished this conservation with a minimum of disruption. Millions of people simply looked at the higher price of gasoline, and they decided that some of their driving was not worth the increased cost. Each person decided whether and how much to conserve, and each person who conserved decided which activities to curtail. We did not need ration coupons, a national oil allocation scheme, or presidential speeches urging us to save energy; people just responded sensibly to the signal conveyed by prices.

Contrast this to America's experience during the Arab oil embargo of the 1970s, when government-imposed price controls prevented pump prices from rising to reflect the reduced supply of oil. Without a reliable price signal, American families had no way of knowing how much they should conserve, and they had much less incentive to conserve. Instead of conserving, many people wasted time and millions of gallons of gasoline waiting in line at filling stations for fuel that was sold at an artificially low price. Price controls prevented Americans from adjusting to the reality of a temporarily reduced oil supply.

²⁰Friedrich Hayek, "The Use of Knowledge in Society," in Hayek, *Individualism and Economic Order* (Chicago: University of Chicago Press, 1945).

The price system facilitates amazing coordination in a market economy. Every day, millions of people make all manner of decisions by comparing the prices they see with the benefits they expect from products or services. Not even the most powerful computer could make all of these decisions for society, but ordinary people can make decisions for themselves when aided by the information summarized in prices.

Bringing Prices Inside the Firm

The size and complexity of resource allocation decisions within firms sometimes rival the size and complexity of decisions in the external marketplace. Yet the typical business firm employs the price system only sparingly. Many companies do establish transfer prices for products that move between internal divisions, but the vast pool of resources known as "corporate overhead" usually carries no internal price. Indeed, a recent survey by Price Waterhouse revealed that most companies are only just beginning to tackle the problem of internal pricing for corporate services.²¹ In many companies, resource allocation for services is managed by corporate bureaucracies that more closely resemble Soviet planning boards than entrepreneurial businesses.

During the past ten years, though, some firms have made major strides in developing internal market systems to guide internal resource allocation decisions.²² The creation of internal markets stemmed from the realization that many "corporate overhead" functions have traditionally been treated like government-run utilities. Instead of receiving resources from customers who voluntarily decided to buy, these groups frequently

²¹Daniel P. Keegan and Patrick D. Howard, "Making Transfer Pricing Work for Services," *Journal of Accountancy* (March 1988), pp. 96–103.

²²William Hatal, Ali Geramanyeh, and John Proudehnd, *Internal Markets: Bringing the Power of Free Enterprise Inside the Organization* (New York: Wiley, 1993).

received budgets from top management. To cover these costs, profit centers then paid arbitrary "overhead" allocations that bore little relationship to their actual use of corporate services, much less the value created by such services for the corporation. As a result, profit centers had every incentive to use as many corporate services as they could—even if a given project consumed more resources than the value it created.

This overuse of corporate services often created the impression that services were undersupplied—an impression that could be used to argue for spending *even more* on overhead services in the future. The predictable result was often a corporate overhead cost spiral, which many companies addressed through "across-the-board" budget cuts. Across-the-board cuts, arbitrary by their very nature, fail to take the relative value of particular corporate services into account. Yet without some kind of market-type evaluation system, most alternatives are relatively arbitrary.

Frequently, business leaders and economists dismiss internal market ideas with a brusque statement that firms exist to minimize transaction costs. Administrative fiat supposedly reduces transaction costs, and so there is seemingly no place for the price system inside the firm. But these objections ignore the "costs" of making decisions without the knowledge provided by prices. No one disputes the notion that, at some level, internal pricing creates more transaction costs than are profitable.²³ But some innovative companies have achieved tremendous increases in productivity by organizing internal service providers as business units charging explicit prices for specific services.

Koch Industries' internal market system provides an interesting example. Services provided under Koch's internal market

²³For a detailed analysis of transaction cost and pricing issues, see Jerry Ellig, "Internal Pricing for Corporate Services," Working Papers in Market-Based Management, Center for Market Processes (Sept. 17, 1993).

system include accounting, training, government affairs, information services, legal, environmental compliance, and a variety of other functions. When confronted with explicit prices linked to discrete choices, business leaders face strong incentives to "buy" only those specific "overhead" services that are really worth the cost. During the past two years, a number of Koch corporate service groups have made major revisions in the types of services they offer, because internal markets have forced them to provide services that internal customers perceive as valuable.

Examples of these services include development of certain reports and studies requested by senior management. In the absence of prices for research and reports, top executives asked for a lot of information on sundry topics; various departments dutifully supplied them, assuming that management knew the costs and had decided the activity was worth the cost. In reality, executives had little idea what the company paid to generate these reports. When prices for these services were presented to management, it quickly scaled back its requests, and some types of reports were eliminated entirely. On the other hand, several new reports were developed jointly by the report "suppliers" and their "customers" in management. These documents now provide managers with much more useful information, such as information on business unit profitability rather than raw data. Yet they would probably not have been developed without the incentives created by the internal market system.

Like Koch's profit centers, its internal service providers are not merely freed to do whatever they think will produce revenue for themselves. They are currently nonprofit entities whose survival depends on their ability to offer services that internal customers are willing to buy. Initially, most of Koch's internal service providers did not have to compete with outside vendors. But as the internal market system has evolved, more and more outside contracting has taken place. Currently, if an internal customer

SUMMARY: PRICE SYSTEM AND INTERNAL MARKETS

COMMAND	SOCIETY	ORGANIZATION
MARKET-BASED	<ul style="list-style-type: none"> • Prices summarize information from utilities and consumer values • Price changes indicate need for reallocation of resources • When consumers react, prices allow adjustments to occur "automatically" 	<ul style="list-style-type: none"> • Internal markets convey similar information to market prices • Investment in corporate services is determined by value added, not politics • Corporate staff grows or shrinks according to ability to serve internal customers, not set by arbitrary limits

wants to purchase from an outside supplier, the internal service group acts as advisor and purchasing agent. The internal agent is always the "supplier" in this system, although it may not necessarily be the specific "generator" of the service. Even the corporate chairman's office is operated as a profit center, purchasing some services deemed essential to the well-being of Koch Industries as a whole.

Obviously, Koch Industries' implementation of internal markets differs from that of many other companies. Many proposals for internal markets sound like trust-busting gone wild; when the whirl of decentralization is finished, there seems little justification for keeping a bunch of independent business units inside the same firm. Koch's corporate services currently are nonprofit entities, not because the company's executives are certain that this is the best way of organizing internal markets, but because they are searching for a solution that captures the benefits of internal markets without sabotaging teamwork.

The transition to internal markets demonstrates some of the challenges Koch has encountered in implementing its management philosophy. Market-based management does not mean merely mimicking markets inside the firm. Rather, it requires managers to understand the major features of a market economy, then adapt these features as needed to improve management practice. Koch's combination of profit centers and nonprofit service groups, along with the evaluation criteria for managers, are an attempt to capture the benefits of a market economy while preserving the benefits of having these entities in one business firm.

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GENERATION AND COMMUNICATION OF KNOWLEDGE

An effective organization must tap the vast and diffused knowledge held by its employees. Decisions must be made by certain people and should be based on the best available information. For many organizations, getting the right information into the hands of the right people can mean the difference between profitability and failure. Many companies now realize that, whatever other businesses they are in, they are also in a kind of "knowledge business." In the business of generating and communicating knowledge, market-based systems have major advantages over command-based alternatives.

The price system serves as a communication network that links and coordinates individual decisions in a market economy. Internal markets can help capture some of the benefits of the price system inside the organization. But in addition to prices, many other aspects of a free society also promote the generation and use of knowledge. Three important characteristics of knowledge help show the power of market-based management in generating and utilizing ideas: much knowledge is dispersed (or "local"), much knowledge is difficult to articulate (or "tacit"), and potential knowledge needs to be tested.

Much Knowledge Is "Local"

Regardless of how decisions and information are communicated, a free society allows—and even requires—that key decisions be made by a vastly greater number of people than a command system. And since knowledge is, by its very nature, widely

dispersed among individuals in society and organizations, a system that allows people with appropriate knowledge to make decisions also must permit fairly decentralized decisionmaking. This does not mean that *all* systems that promote decentralized decisions are good, only that any system which cannot accommodate decentralized decisionmaking fails to take full advantage of the knowledge contained in the system.

The power of the market system lies largely in placing decisionmaking power in the hands of those with the appropriate knowledge. In a market economy, we see dramatic decentralization of decisionmaking, but we also see some cases where one or a few people make decisions that affect vast collections of resources. In many cases, the appropriate level of decisionmaking is much closer to the customer than to corporate headquarters. But it would be a mistake to view market-based management as always requiring more decentralized decisionmaking. When decisionmaking authority is placed at too local a level, the decisionmaker lacks the appropriate knowledge because he "can't see the forest for the trees." This kind of misplaced authority can be just as disastrous for an organization as having top management make all decisions.

The important point is that, where the critical knowledge is local, the market system permits decisions to be made at the local level. A market-based organization needs to approximate this distribution of authority to achieve its potential. But appropriate distribution of authority is not enough. Even a person with the appropriate knowledge won't make the best decisions unless he or she has the proper incentives to do so. For this reason, the organization's incentive system must be developed to maintain the harmony of interests between the individual decisionmaker and the organization.

Much Knowledge Is "Tacit"

Much of the most important knowledge contained in societies and organizations is inarticulable—or what philosopher of science Michael Polanyi calls "tacit." One example is knowledge of how to ride a bicycle. While many people know how to ride one, no one could articulate this knowledge in any complete way. Polanyi captures this state of affairs by saying, "We know a great deal that we cannot tell."²⁴ Another often-cited example of tacit knowledge is language. When we learn to talk as children, we also learn a complex set of grammatical rules that very few of us can articulate, but almost all of us use on a daily basis. Other direct examples from organization management might be the knowledge of how to achieve maximum output from an assembly line or get maximum quality from a given production procedure.

Management literature features plenty of examples of companies that have found ways to capture local and tacit knowledge. How? By permitting individual initiative, creativity, and experimentation. While a command system relies on an explicit, articulated set of regulations establishing which decisions will be made by which people (often even specifying the information on which the decision will be based), a more market-based system permits flexibility and creativity in accomplishing the overall goal. The recognition that much of the crucial knowledge needed for maximum performance lies beyond the reach of the manager implies an entirely different approach to getting a particular job done.

An example from Koch Industries demonstrates what happens when an organization mobilizes the knowledge of its employees. At one processing unit, managers achieved a large increase in

production simply by telling the unit operator to produce as much as he thought the unit could produce, within safety and legal tolerances. Formerly, he had explicit instructions to produce the maximum amount that engineers said the unit was designed to produce within the same tolerances. Koch management acted on the possibility that the unit operator might have superior knowledge in his area of expertise, and they were right. In this case, a seemingly small change had major results.

Much Knowledge Is Untested

How an organization or a society deals with new and untested ideas can have a major impact on its performance. In fact, we believe that the way in which the former Soviet Union stifled creativity and innovation is directly linked to its eventual downfall. In a command economy, people fear speaking up, because they are often punished if they disagree with the official doctrine. This is an unavoidable feature of centralized economic planning, because ordinary individuals are not supposed to be able to improve on the government's economic plans. Such a system clearly limits the creation and communication of knowledge. For decades the Soviet Union discouraged (and often persecuted) individuals engaged in scientific inquiry that was not condoned by the government. The system was clearly based on the idea that the government "knew" what needed to be discovered, and any other intellectual pursuits ran counter to "progress."

As misguided as the Soviet system sounds, it is likely that the real problem was not irrational or stupid government officials, but rather the inevitable result of a command-based system. How different, in principle, was this system from a corporate system in which new ideas must be passed through multiple and hostile "channels" in order to be heard by top management? How likely are creative suggestions to occur in a com-

²⁴Michael Polanyi, *The Tacit Dimension* (New York: Doubleday, 1983), p. 61.

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GENERATION AND COMMUNICATION OF KNOWLEDGE

pany within which success comes from protecting divisional budgets, protect "turf," or some other variable unrelated to tapping the knowledge of employees? And how many companies don't have at least some elements hostile to new and untested ideas? We believe no company is completely immune to Soviet-style suppression of new ideas, and it is therefore critical for each company to examine its own systems for finding and testing these ideas.

Does the common tendency for people to suppress new and threatening ideas imply that *all* new ideas should at least be tried? No. But the systems a company uses to generate new ideas and select those that will be tried should be designed to avoid as many command-based shortcomings as possible. For example, rather than designating a fixed "channel" through which an idea must pass (such as a specific person), a system of several possible avenues might be arranged. This would more closely approximate a market-type system, since the "idea entrepreneur" would be able to choose the reviewer least likely to be threatened by the new idea. The ideal idea reviewers would be people with credibility in the organization but who would be unlikely to behave as authoritarians.²⁵ The reviewers would also be responsible for advancing the organization's mission by helping generate new ideas, and they would be rewarded based on their success in this area.

Freedom of expression, multiple idea filters, and mutually agreed upon standards of evaluation are positive features of a non-authoritarian scientific community described by Michael Polanyi as a "society of explorers."²⁶ Polanyi contrasts this kind of society with what he calls a "dogmatic society," which corresponds to our concept of a command society. The society of

²⁵Don Lavoie and Bill Tullloh, "The Use of Knowledge in Organizations," Working Papers in Market-Based Management, Center for Market Processes (forthcoming 1994).

²⁶Michael Polanyi, *The Tacit Dimension* (New York: Doubleday, 1983), p. 83.

SUMMARY: KNOWLEDGE GENERATION AND COMMUNICATION

COMMAND		ORGANIZATION
MARKET-BASED	<ul style="list-style-type: none"> • Ideas are welcomed and filtered by people who have responsibility and incentives to help generate knowledge • All recognize that new knowledge may invalidate existing shared assumptions about business • "Authority" is conferred (or lost) by one's track record, not by political power or rank 	<ul style="list-style-type: none"> • Decisions are made by those with the most knowledge and right incentives • Ideas are welcomed and filtered by people who have responsibility and incentives to help generate knowledge • All recognize that new knowledge may invalidate existing shared assumptions about business • "Authority" is conferred (or lost) by one's track record, not by political power or rank

explorers is not without standards for determining the quality of ideas, but it is without centrally directed standards and channels. The standards are mutually held and reinforced (and sometimes even changed) by the members of the society themselves. It is this kind of system that seems to produce the most innovative ideas and thinkers, and a market-based system of creating and communicating knowledge should take this ideal as a model.

INCENTIVES, COMPENSATION, AND MOTIVATION

The Social Role of Profit

The market system is critical if people are to receive rewards for helping others accomplish their goals. The prospect of profit motivates entrepreneurs to seek ways of delivering the most value to consumers for the least cost. Through their purchases, customers reward those who do a better job of satisfying their needs using fewer resources.

Some critics of the market object that the business leader's obsession with profitability prompts companies to pursue only short-term goals. This objection ignores the way markets capitalize future profits into the price of assets. In a market system, transferable property rights create powerful incentives to conserve and care for valuable resources. For example, when a corn farmer sells his farm, the price he gets depends on its condition. He has an incentive to ensure future productivity, so he leaves it in a condition that minimizes future costs and maximizes future revenues. In other words, by doing things that make the farm fetch a higher price today, he ends up taking the needs of

future generations into account. In the case of a corporation, it makes much more sense to maximize the long-term net present value of the corporate income stream than to maximize short-term earnings. The market system thus contains strong incentives to provide for the future.

In contrast, a farmer in a socialist system like the former Soviet Union received rewards for meeting his quotas, not for thinking about the future. He could use the land, but he could not sell it, and so he had little incentive to preserve or enhance the land's value for the future. Ultimately, he would leave the property in worse condition than when he received it. This principle explains why environmental problems in the formerly socialist countries dwarf those that we face in the West. In Eastern Europe, sulfur emissions from coal-burning factories have completely denuded some forests. Water in rivers is so loaded with toxic chemicals that it is not even fit for industrial use. These results stem directly from the incentive system: pushed to meet production quotas, people did the things they were rewarded to do and no more.

Personal Profit and Loss

Psychologists, economists, and others have produced mountains of theories and research about motivating people inside organizations.²⁷ Market-based management adds not another theory of motivation, but a framework for integrating the existing research and deciding which ideas are most useful.

Inside the firm, an effective motivation system conveys market signals to each employee. To fully understand the implications of this statement, we need to remember that the profit-and-

²⁷For example, see Frederick Herzberg, "One More Time: How Do You Motivate Employees?," *Harvard Business Review* (Sept.-Oct. 1987), pp. 109-120, and George P. Baker, Michael C. Jensen, and Kevin J. Murphy, "Compensation and Incentives: Practice vs. Theory," *Journal of Finance* (July 1988), pp. 593-616.

loss mechanism accomplishes several things in our broader society. It offers the prospect of rewards, conveys information, and redistributes control over resources. Each of these elements has a parallel in an organization's motivation system.

Within organizations, no aspect of motivation generates as much controversy as the issue of rewards. Some people think of incentives in a very mechanical and superficial way, assuming that people are naturally lazy and that financial and material rewards are the main things that motivate them. The motivation issue then simply becomes a question of discovering the "right" amount of pay and perks to elicit the "right" amount of effort. Many authors and business leaders have reacted against this view, arguing that intrinsic motivation—the individual's desire to accomplish something—is the main force that drives achievement. Unfortunately, some take this sensible notion to the opposite extreme, asserting that material rewards do not matter much, as long as people have fulfilling work in a good environment. This notion sometimes surfaces in the political realm as well. It is used to justify a ideological agenda that seeks more egalitarian pay scales and more progressive income taxation.

Market-based management offers a third way, different from either of these two extreme views. In general, people do want to make a positive contribution and do the best job they can. In many cases, though, organizations give people incentives to do just the opposite, and it is an exceptional person who can resist these incentives for a long period of time. Nearly every organization has stories of heroic people who succeeded in doing their jobs in spite of the system. The goal of a market-based company should be to create a motivation and incentive system that will reinforce people's natural desire to do the right thing.

How does one decide what "doing the right thing" means? While we can't give blanket criteria, we can suggest the following:

- Properly defined roles and responsibilities, as indicated by the individual's and organization's mission, are critical.
- Measures should reinforce the "harmony of interests" created by the compatible missions of the individual and organization. When an employee's action benefits the organization, it should benefit the individual as well.
- Behavior important to the organization—such as adherence to codes of conduct, principles, and other personal characteristics—will be taken seriously only if included in employee evaluations.
- Use of multiple measures, rather than only one or two, will help minimize the natural tendency to slip into behavior that improves calculated performance rather than true performance.

Carefully developed measures are especially important in large organizations, where people may be quite insulated from direct contact with the external marketplace. It is here that the organization's incentive system, understood in the broadest possible sense, is most crucial as a means of conveying information. People in a big company may sincerely want to do their best to serve the customer, but they need meaningful feedback to guide them. Furthermore, verbal evaluation and discussion by themselves may not provide sufficient information to guide action, because "talk is cheap." When administered sensibly, tangible rewards—in the form of pay, bonuses, greater responsibility, or other benefits—help underscore the most important things an employee can do to serve customers.

There is a third, distinct reason that advancement and compensation should depend on results: the imperative of matching people with the most appropriate responsibilities. In the marketplace, a small business owner who successfully serves customers will often earn higher profits and have the opportu-

SUMMARY: INCENTIVES, COMPENSATION, AND MOTIVATION

COMMAND	SOCIETY	ORGANIZATION
	<p>• Most compensation is based on measured performance, specific measures and targets are often developed by top corporate brass</p> <p>• Rewards for climbing corporate ladder are based on compliance with corporate plan and adherence to corporate dogma</p> <p>• Dissent from official assumptions is especially dangerous</p> <p>• Criticism of government or dissent from official dogma is punished severely</p>	<p>• Compensation is based on seniority, number of employees managed, etc., rather than value added</p> <p>• Where compensation is based on measured performance, specific measures and targets are often developed by top corporate brass</p> <p>• Rewards for climbing corporate ladder are based on compliance with corporate plan and adherence to corporate dogma</p> <p>• Dissent from official assumptions is especially dangerous</p>
MARKET-BASED	<p>• Profit opportunities encourage entrepreneurs to serve consumers</p> <p>• Successful entrepreneurs get control of more resources; unsuccessful ones are separated from control of resources</p> <p>• People have financial incentives to work in jobs where they can add the most value to society</p>	<p>• Changes in compensation are linked to mission, including helping overall organization and commitment to corporate values and culture</p> <p>• Changes in responsibilities depend on employee's record in using resources to advance the mission</p> <p>• Employees are rewarded for moving to new jobs where they can better contribute to the mission</p>

nity to make even more resource allocation decisions in the future. This continual redistribution of resources serves the important social function of moving each decision into the hands of the person with the best knowledge and judgment. A career development and compensation system should attempt to replicate these aspects of the market economy. Employees who make greater contributions to profit should enjoy greater opportunities to determine their own work and make decisions about the use of company resources. Many psychologists have argued that this type of motivation system makes people work harder because they feel better about their work. Just as important, it helps the organization allocate decision-making authority to the right people.

THE RESULT: SOCIAL AND ORGANIZATIONAL LEARNING

Ultimately, a free economy generates vast wealth because it effectively uses individuals' knowledge in decisions. This "social learning" is a crucial element in economic progress, because of the dispersed and tacit nature of economically useful knowledge. The more effectively a society uses knowledge, the higher its standard of living, because better know-how lets us satisfy more consumer desires using fewer resources.

Social Learning

The incentive problems in a command system are generally well recognized, but the knowledge problems of a command system are not. The market system has the highest rate of social learning of any economic system because its rules of just conduct and property rights systems help generate a rich

flow of information from two important sources: verbal exchanges and market transactions.

Markets promote learning because consumer choices determine rewards for entrepreneurship. Society benefits from the individual knowledge each consumer reveals in market exchanges. When competition forces firms to improve their ability to satisfy consumer needs, learning occurs. Without consumer choice, there would be much less learning or coordination in society. Command systems find it much more difficult to tap dispersed knowledge and "learn," which is a key reason why command systems fail. This failure of centralized planning also helps explain why large firms that use command systems are so inefficient. They fail to use everyone's knowledge, precisely because they are centrally controlled.

If planners impede market decisionmaking, coordination must occur in some other way. The central authority typically tries to specify the quantity and quality of the things to be made. But typically, government planners find that their plans are unworkable because they lack the necessary knowledge. For instance, when Soviet planners expressed a nail factory's quota in tons of nails per month, the factory produced a glut of large nails but a shortage of small nails, because that was the easiest way to meet the quota. When the quota was set in numbers of nails per month, the factory produced millions of tiny nails but no large ones. Both of these results occurred because planners rewarded factory managers for meeting their quota, and so the managers found the least difficult way to achieve it. Even with quotas expressed in particular sizes of nails, there were shortages of some and surpluses of others—because the planners could not really know the total number of every type of nail that was needed.²⁸

Even if the planners could have gotten everything exactly right once, neither consumer desires nor production technologies

²⁸Thomas Sowell, *Knowledge and Decisions* (New York: Basic Books, 1980).

stand still. To plan an economy or an organization effectively, those in charge need to anticipate continual change and respond effectively. A market system, in contrast, does not require such an impossible collection of knowledge and power. Firms that are skilled at anticipating future trends reap profits, and the prospect of profit spurs business leaders to adjust to change.

Organizational Learning

Organizational learning is the business firm's counterpart to social learning. Great differences in the rates of learning among firms stem from organization and management, because organization and management determine how well the firm uses the knowledge of its people in decisions.²⁹

The Japanese and American auto industries provide a well-known case in point. Compared to U.S. auto firms in the 1980s, the Japanese were twice as productive, had one-third fewer defects, maintained less than eight percent of the inventory, and required half as many people in product development.³⁰ Japanese firms achieved these results because they found better ways to marshal the knowledge of individual workers and work teams.

The Japanese emphasis on mobilizing the knowledge of workers, their rejection of the "scientific management" theories of Frederick Taylor, and their strong sense of the superiority of their techniques, all come through quite clearly in the following quotation from Konosuke Matsushita:

We will win and you will lose....Your companies are based on Taylor's principles. Worse, your heads are Taylorized too. You firmly believe that sound management means executives on the one side and workers on the other, on the one side men

²⁹Ray Stata, "Organizational Learning: The Key to Management Innovation," *Sloan Management Review* (Spring 1989), pp. 63-74.

³⁰James P. Womack, Daniel T. Jones, and Daniel Roos, *The Machine That Changed the World* (New York: Rawson Associates, 1990).

who think and on the other side men who can only work. For you, management is the art of smoothly transferring the executives' idea to the workers' hands.

We have passed the Taylor stage. We are aware that business has become terribly complex. Survival is very uncertain in an environment filled with risk, the unexpected, and competition. Therefore, a company must have the constant commitment of the minds of all of its employees to survive. For us, management is the entire work force's intellectual commitment at the service of the company.... We know that the intelligence of a few technocrats—even very bright ones—has become totally inadequate to face these challenges.... Yes, we will win and you will lose. For you are not able to rid your minds of the obsolete Taylorisms that we never had.³¹

Mobilization of knowledge is critical in the Japanese systems. Strategies like just-in-time inventory management, pioneered by Toyota, can work only if companies organize work in ways that tap the dispersed knowledge of individual workers. Many Japanese auto firms accomplish this by making each worker or work team responsible for inspecting the parts they receive from the previous stage of production. When defects are discovered, the parts are returned to the previous stage for repairs—a significant form of immediate feedback. Since workers know that they will be held responsible for correcting problems appearing at their stage, they have strong incentives to minimize defects. Given this division of responsibilities, it is sensible for the individual worker to learn statistical process control and other techniques that enhance quality. But note that the result—low

³¹Konosuke Matsushita, "The Secret is Shared," *Manufacturing Economics* (February, 1988), p. 15.

defect rates—stems from the definition of responsibilities, just as the productive results in a market economy stem from the underlying structure of property rights.

It is tempting for management to adopt command practices when employees fail to do exactly what is expected of them. The easy response is to try to specify exactly what the people will do. However, giving orders and ignoring the knowledge of the people in the organization will generate the wrong decisions, will hamper employee motivation, and will likely produce results about as spectacular as those in the now-defunct Soviet Union.

CONCLUSION

Because the key systems of organizations discussed in this booklet are so heavily interdependent, we suspect that the principal elements of market-based management probably need to be implemented as a coherent system in order to achieve their full potential. This conjecture is certainly consistent with the experience of Koch Industries. An incentive system, for example, makes little sense unless people first understand the organization's mission.³² Similarly, an attempt to create internal markets without profit centers and carefully defined roles and responsibilities will create chaos.

³²Acceptance of an incentive system can also depend on the organization's values and culture. For an example, see Kenneth W. Chilton, "The Double-Edged Sword of Administrative Heritage: The Case of Lincoln Electric" (St. Louis: Center for the Study of American Business, July 1993).

Changing management approaches is one of the most difficult processes a corporation can initiate, and a transition from command-based to market-based management is as fundamental a change as an organization can make. Effective change requires a strong understanding of how the market process really works—not just how it works in textbooks—combined with a sense of how people will react to different structures and incentive systems. One of the biggest challenges in this process is combining business expertise with a strong knowledge of economic concepts. This combination, though rare, seems essential for continued development of the market-based approach.

This realization has shaped our approach to developing market-based management at the Center for Market Processes. Market-based management is not an off-the-shelf program that business managers can buy and install. Rather, it is a perspective that permeates our approach to analyzing and improving major organizational systems. We invite interested executives to join with us in developing and applying market-based management, to help modern organizations fully tap the unique knowledge and expertise of all of their employees.

The nature of today's business environment shows that organizational change and improvement are not just smart choices—they are necessary for survival. Command-based societies have found themselves unable to survive when faced with market-based alternatives, and command-based companies will suffer the same fate when confronted with market-based competitors. It is no accident that today's most innovative and successful management techniques are those that mobilize the vast knowledge dispersed throughout organizations. Their success points to the need for an overall approach to management that continually uncovers and mobilizes this knowledge.

We believe the coming decades will see the paradigm of command and hierarchy replaced—in practice as well as in theory. The new paradigm will allow employees to apply their knowledge and skills with minimal “management” in the traditional sense. It may or may not be referred to as market-based management, but to work effectively it must be based on many of the principles described in this booklet. And while there is still much work to be done, market-based management clearly has the potential to serve as a guide for designing and building the organization of the future.

About the Center for Market Processes

The Center for Market Processes is a nonprofit research and education organization affiliated with George Mason University in Fairfax, Virginia. The Center's program on market-based management is designed to develop and apply market-based solutions to critical management problems faced by today's organizations. Toward this end, the Center produces educational publications and conducts research projects, case studies, and management workshops. The Center also offers consulting services to help organizations improve their profitability by developing and implementing market-based management systems.

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How to Succeed in Interesting Times

By Charles Koch
Chairman of the Board and CEO
Koch Industries, Inc.

Many of us now have personal knowledge of why the Chinese regarded their saying "May you live in interesting times" as a curse. The maelstrom of change in today's business world hasn't been seen since the Industrial Revolution in the 18th and 19th centuries.

What is creating such rapid change? Most of us would agree that it's the revolution in IT and communications, leading to innovations ranging from futures markets to the Internet that more rapidly educate customers and competitors alike. Thus, good margins seemingly disappear in an instant and product life cycles have drastically shrunk. So, today, maintaining a business is, in reality, liquidating it.

For many, the first reaction to change of this magnitude, and the uncertainty, frustration, and fear it brings, is denial and resistance. But, if we give in to this first impulse and resist the forces of progress, as the Luddites did when they smashed the new textile machinery, we become overwhelmed by them.

Succeeding in this environment of revolutionary change, requires that instead of resisting change, we focus on what's required for us to lead the change, to make a real contribution. This means acquiring a new framework of mental models that better enables us to create value during rapid change. Mental models aren't computer programs, but the mental constructs we all use to connect to reality. So what are the characteristics our mental models need to get us and keep us on a productive path?

Most importantly, our models must fit reality. We all recognize how a faulty model, such as, "gravity doesn't apply to me", brings disaster. We have a word to describe people whose models don't connect with physical reality - insane. But we often fail to recognize the fallacies in our models of how we can create value and best live and work together. We don't seem to notice when people don't connect with the reality of human affairs -- with just as disastrous consequences.

For example, if we resist change, the mental model we're using, whether we recognize it or not, is: What worked in the past will work in the future. Consequently we don't feel compelled to find new ways to create value. To succeed, we must replace this model with one that the marketplace is an experimental discovery process of creative destruction. For most of us, the difficulty is that experimentation means failures, so to succeed we've got to be willing to fail. The brutal irony is the more we try to avoid specific failures, the more we ensure overall failure.

And we need to replace the model that we can profit long term by government subsidies or protection from competition, with one that admits that we must create superior value for our customers. In other words, going from a model of profiting by political means to one of profiting by economic means.

So how do we go about developing this new, more reality-based framework of mental models? Do we accept the latest fads or the theories of the current hot guru? (total quality, re-engineering, etc.) Or do we examine the lessons from human history on how prosperity and social progress are created? To ask the question is to answer it.

In human history, life for over 99 percent of humanity has been, in Hobbes' words, "nasty, brutish, and short". Prosperity for those other than rulers has only come on rare occasions through a form of social organization called a free society. By a free society, I mean a society whose foundations are: Justly acquired private property, freedom to exchange that property, the resulting markets -- prices, profits and losses, individual liberty including freedom of expression and mobility of labor, the rule of law, and a culture based on beneficial rules of just conduct.

You will recognize these as the same foundations that made America the most prosperous country in the world. Harnessed by business, they can prove just as powerful.

In striving to apply these lessons at KI, we have developed a framework we call Market Based Management (MBM). In applying MBM, we've found that full understanding of its concepts and values is critical. Without this understanding, it is almost a certainty that the framework will be misapplied. And the conceptual understanding gained from formal education is not sufficient. Understanding as Howard Gardner defines it is required -- being able to apply automatically and routinely to get superior results. For example, we understand chess, not when we know the rules of the game, but when we instinctively know how to use the rules to create winning strategies.

The understanding or skill we need is what enables us to convert a set of rules or a language (including math) into effective tools for solving problems and making discoveries. But this skillful application is a much more difficult form of understanding to acquire -- in part because if we are glib in a concept it is easy to delude ourselves that we really understand it. It is as if someone who learned the theories underlying golf solely by reading about them believed he was ready to go on the PGA tour.

Surprisingly, we don't typically find this depth of understanding in professionals. Because their focus, instead of being on the problem, tends to be on the tools they have learned -- they have a hammer in search of nails. We see this tendency, for example, in venture analysis where what is analyzed is determined by the computer program available, such as "crystal ball," rather than why they want to do the deal. It seems we all have to learn the hard way that the more valuable skill is in selecting the best tools for the problem, and that doesn't necessarily mean more sophistication in analysis.

This focus on the tools rather than the problem is a form of the more general disease of focus on the parts rather than the whole, which is a primary cause of business decline. Its symptoms are bureaucracy, "functionalitis," and a lack of teamwork. An example is sales and manufacturing warring rather than combining their different perspectives to create value.

I don't pretend to have all the answers to these problems, in fact, we make more mistakes than most, but our market-based framework has proven effective at KI. The little bit we've understood about MBM has enabled us to grow two hundredfold over the last 30-some years -- to where, if we were public, we would rank 21st in the Fortune 500.

MBM starts with developing a tool kit of market-based models. Our tool kit now contains approximately 80 models, which, following Einstein, "make as simple as possible, but no simpler," are grouped into five elements: vision, virtue and talents, knowledge systems, decision rights, and incentives.

After gaining conceptual understanding of these models we use them, first, to identify the problem and root causes, then, to develop a course of action, and, finally, to create measures of progress. These measures provide feedback enabling us to improve both our understanding of the tool kit and each step of the process.

To give you a feel for MBM, I'll briefly review the five elements and explain how they help build businesses with superior profitability and growth.

1. Vision

I begin with Vision because every significant improvement in each of our businesses was preceded by a change in vision.

We believe this is so because our vision determines what we see and do. As Einstein put it, "whether we can observe a thing depends on the theory (vision) we use." We use MBM to help us develop the vision to see the invisible, to see what could be, not just what is.

Developing a vision with this power begins with the model that a market economy is an experimental discovery process for finding what people value.

The next model we apply is that a business is a vehicle for integrating knowledge to create value. This leads us to a process for understanding the value chain and matching our capabilities with the opportunities. We call this the Value Creation Process, which guides us in building superior knowledge generation and opportunity capture.

Take our analysis of the beef value chain. Today, cattle are bred, fed, prepared and sold on averages. So cost/value relationships on individual animals are lost. And market signals on the cuts and qualities that consumers value are not used to guide activities in the value chain. This is a major reason beef has declined relative to chicken. To overcome this problem, we are building a knowledge network to track the quality of each animal that has the potential of increasing its value to the consumer by more than 50 percent.

Understanding the value chain leads to a different vision of our real customer. In beef, it is the consumer of meat. So when the immediate customer of our feedlots, the meat packer, blocks the value creation process, we restructure the relationship.

Our market-based framework also provides a different vision of integration than the traditional one of vertical integration of physical assets, as with the major oil companies owning everything from the oil well through the gas pump. Instead, this vision is of the integration of knowledge, not assets. It is a vision of restructuring the way value is created and delivered, not incremental improvement.

This radical vision has led us to build a different kind of company -- one that combines all four types of firms -- industrial or operating, distribution or trading, finance or investment banking, and service or consulting. We bring our value creation process into being by integrating knowledge and capabilities both across these four types and across our business groups. In this process, the focus is on the customer, on value creation, not on the product.

From this process we developed the vision for KI: "Satisfying basic needs for a better quality of life through discovery". The basic needs we believe KI can better satisfy are segments of: energy, transportation, food, shelter, materials, finance, and management. To realize this vision, we are organized in ten business groups: Refined Products, Petrochemicals, Crude Oil Services, Gas Liquids, Energy Services, Materials, Chemical Technology, Minerals Services, Agriculture, and Capital Services.

An example of creating value by integrating these capabilities is our Producer Services business, which involves purchasing, transporting, trading, and processing oil and gas, and providing financing, risk management, M&A, and management services. Another is our road business which, in evolving from selling low cost asphalt, to supplying performance asphalt, to, now, owning the performance of roads or even the roads themselves, has required integrating all four types of firms.

2. Virtue and Talents

This element is guided by Jefferson's model of a free society as replacing hierarchy with a civil society based on virtue and talents.

We find value creation begins with a culture conducive to discovery. Thus, we must select people, first and foremost, on virtue, values, and on talents, rather than on credentials, how well they test, or even experience.

What are some of the values critical to discovery? One is passion -- a passionate commitment to creating and producing. Another is humility, or recognizing what you don't know. As Daniel Boorstein put it "The greatest obstacle to discovery is not ignorance but the illusion of knowledge".

Discovery also requires that we put into practice the market-based model on diversity, specialization and the division of labor. Human beings and what they can contribute are much more complex than a single number such as grades or a GMAT score can indicate.

What a group of individuals with diverse skills can create through teamwork and choice far exceeds what anyone working alone, no matter how smart, can achieve. MBM is in direct opposition to the traditional command-and-control framework of orders and execution, with the firm, at best, only as smart as its leaders, and usually not as smart as anyone in it.

3. Knowledge Systems

In most firms, there are few internal market signals to enable employees to see the connection between value and costs so the focus is on pleasing the boss, not the customer. Instead of allocating resources through a dynamic market process, it is done through command & control techniques such as budgets, quotas, and detailed assigning of tasks. There also tends to be knowledge hoarding which leads to the loss of the firm's most important asset -- the knowledge of its people.

To address these problems, we eliminated the requirement for budgets and replaced them with a knowledge process that reveals what customers value and the availability of resources, much as prices and P&L do in a market economy. This requires grouping costs, not by accounting categories, but in a way that connects to value. For example, we don't look at maintenance costs in themselves, but as a part in the net benefits of reliability.

We also attempt to create a free marketplace of ideas, including setting up challenge processes using those with the best knowledge, not hierarchy.

4. Decision Rights

In many companies, there is tremendous waste in the decision rights system. Reaching a decision is so difficult and time consuming that opportunities are lost and ideas are stifled. Hierarchy, not the best knowledge, determines who makes decisions. This inhibits initiative and risk-taking, and leads to the tragedy of commons and management by fiefdoms.

In contrast, we try to apply the market process of continually moving resource decisions into the hands of those proven best at creating value (through changes in resource control through P/L). Decision rights vary by type of decision with ownership for each key activity.

5. Incentives

Finally, the incentives in organizations typically undermine value creation. Losses are punished much more than profits are rewarded. People are rewarded only for current earnings and making their part look good, not long-term value creation for the whole.

In the radically different market-based incentive model, entrepreneurs in a free economy are rewarded by keeping a portion of the value they create. Applying that model, we attempt to compensate people according to long-term value created for KI. Salary is viewed only as an advance on compensation for value and compensation has unlimited upside.

That sums up the five key elements of Market-Based Management. We have found it has tremendous power, but only when all five elements are applied in a mutually reinforcing way. Because the whole is not simply greater than the sum of the parts; it becomes a different entity. Just as a living thing is a different entity than a collection of molecules, an organization that combines all these elements becomes something different than the ordinary collection of people, activities and assets. I have seen its power when applied to all types of work and activities, as well as to the business as a whole.

Take, for example, a unit operator in a process plant. Traditionally, each day that operator is given detailed instructions -- throughput, yields, temperature, pressure, etc. Going from that command-and-control framework to a market-based framework leads to amazing across-the-board improvements. In our plants alone, it has contributed several hundred million dollars in throughput, yield, environmental and safety improvements in the last few years.

To capture this power, we must, first, Select operators with the appropriate talent and values -- who are committed to creating rather than the status quo, with the humility required for learning. We must help them acquire the Vision of their job as value creation rather than following instructions, and provide them with the information and measures, the Knowledge, to see how to create that value. Finally, we must provide the Decision Rights to encourage appropriate experimentation, and Incentives that reward value creation. These elements taken together build spontaneous order in the firm so that everyone creates value for the whole.

The power in this market-based framework, of which we are only capturing a fraction, flows from this system of spontaneous order. This is the only order that leads to a discovery process in which people achieve their individual ends by satisfying the ends of others. It brings about a harmony of interest, a civil society, whether in a firm or a nation.

Creating the conditions for spontaneous order is no easy task. It can't be imposed, as seen by the difficulty in creating a market economy in Russia today, where antithetical principles have always been the way of life. Spontaneous order can only arise when its elements become ingrained in the traditions and tacit knowledge of the people.

Such a transformation requires changing lifelong habits which involves tremendous effort. A life change of this magnitude can only be successfully made by someone with a passionate commitment. Without such a commitment, embarking on this journey becomes a fool's errand.

But if someone does have the passion, the journey is well worth the effort. One half of our earnings at KI now come from MBM initiatives undertaken in just the last four years. Further, we have more opportunities today than we've had cumulatively in our entire history. Thus, I'm more excited about our future than I've ever been.

I have a passionate belief in the power of these ideas. I believe they can open the future for anyone who makes the effort to understand and apply this framework. It will enable you to fully develop your potential, both to your benefit and to everyone else's.

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In The Matter Of:

*Danny Smalley, et al v.
Koch Industries, Inc., et al*

*Phillip Dubose
July 9, 1999*

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Page 5

PROCEEDINGS

(1) MR. WOLF: Just want the record to reflect
(2) that I'm producing to Koch's counsel some photographs.
(3) They're on a CD ROM. They're a production of
(4) photographs and information in the files of Plaintiffs'
(5) expert Charles Powell.

(6) PHILLIP DUBOSE,
(7) the witness hereinbefore named, having been first duly
(8) sworn to testify the truth, the whole truth and nothing
(9) but the truth, testified on his oath as follows:

EXAMINATION

BY MR. LYON:

(10) Q: Mr. Dubose, would you state your name for the
(11) record, please.

(12) A: Phillip O. Dubose.

(13) Q: Sir, how old are you?

(14) A: 55.

(15) Q: Where do you live?

(16) A: Lafayette, Louisiana.

(17) Q: And how long have you lived there?

(18) A: Twenty-seven years.

(19) Q: Sir, when did you first go to work for Koch
(20) Industries?

(21) A: January 15th, 1968.

(22) Q: And when did you leave the Koch Industries

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(1) employment?

(2) A: September 6, 1994.

(3) Q: During the period of time that you were there
(4) from 1968 to 1994, what were you involved in as far as
(5) work? What did you do for Koch?

(6) A: I started off in January 15th of '68 in
(7) pipeline maintenance. I was there for a year, and then
(8) I was promoted to a relief gauger. I relief gauged from
(9) '69 to '72, to May 1st of '72. I took over my own
(10) field. I was in charge of the Bayou Bouillon pipeline
(11) system from 1972 to 1981. I think that was Feb —
(12) January 31st of 1981.

(13) I was promoted into the Koch safety
(14) department. Worked in Koch safety department from
(15) February 1 of '81 to September 1st, 1980 — 82. Then
(16) went into the Marine division. Took over my first
(17) management responsibility managing Koch Marine. Managed
(18) Koch Marine all through the time I was — up until the
(19) time I left Koch.

(20) But in 1986 I was — they added more
(21) responsibility to me as a division manager. I took over
(22) all of their trucking in the southeastern part of the
(23) United States. And then in 1992 they added more
(24) responsibility to me, and I was in charge of Koch
(25) Gathering Systems in Louisiana, Mississippi and Alabama

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(1) and Florida.

(2) Q: And when you left Koch in '94, you were a
(3) division manager?

(4) A: Yes.

(5) Q: Okay. And from '86 to '94 you were a division
(6) manager —

(7) A: Yes.

(8) Q: — for Koch; is that right?

(9) A: That's right.

(10) Q: And during this period of time were you as a
(11) division manager, did you have regular occasion to meet
(12) with the upper executives of Koch Industries?

(13) A: Yes.

(14) Q: People such as Bill Caffey?

(15) A: Yes. Tom McCaleb, Doyle Barnett, Keith
(16) Langhoffer, Gary Baker, Darrell Brubaker. That's
(17) probably about it. And then —

(18) Q: Did you meet with Mr. Koch himself?

(19) A: On a few occasions, yes.

(20) Q: Did you participate in meetings that he
(21) conducted with management employees?

(22) A: Yes.

(23) Q: Now, the Mr. Koch I'm referring to is Mr. —

(24) A: Charles Koch.

(25) Q: — Charles Koch.

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(1) A: Yes.

(2) Q: And he's the chief executive manager of Koch
(3) and all of its subsidiaries?

(4) A: Koch Industries, yes.

(5) Q: The chief owner also?

(6) A: Yes, uh-huh.

(7) Q: Do you understand that?

(8) A: Yes, uh-huh.

(9) Q: Now, in regard to Charles Koch, what level —
(10) in your experience as a division manager for Koch
(11) Industries, what level of control did he exercise
(12) over — over the day-to-day operations of Koch
(13) Industries and in particular pipeline safety and things
(14) of that nature?

(15) MR. FAGELMAN: Objection, form.

(16) Q: (By Mr. Lyon) Go ahead.

(17) A: He was in complete control. Mr. Koch was
(18) definitely on top of his business. He knew exactly what
(19) was going on the whole time. He — there was — I
(20) would — this man was definitely on top of his
(21) business. And only way you could get there is to be
(22) involved.

(23) Q: Now, did you ever see him question division
(24) managers about how many employees they had hired or such
(25) things —

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[1] Q: (By Mr. Lyon) Now, during the period of time
[2] that you worked for Koch Industries, do you have any
[3] knowledge of individuals who were killed as a result of
[4] the failure of Koch Industries to operate their
[5] pipelines in a safe manner?

[6] A: Yes.

[7] MR. FAGELMAN: Objection, form.

[8] Q: (By Mr. Lyon) And would you tell the jury
[9] about those people that you know about?

[10] A: The ones I know about —

[11] MR. FAGELMAN: Objection, form. Excuse
[12] me.

[13] A: — is the one in, I think it was in Minnesota.
[14] It was anhydrous ammonia. He was on a dock. I think
[15] they were unloading this cargo. I can't really recall
[16] really what happened, but we had a fatality there. Was
[17] a Koch — Koch employee.

[18] We had several people killed in
[19] North Dakota because of a sour crude deal. This is the
[20] H2S sour gas stuff. I know we've had at least three.
[21] The last one I remember about was the pumper was out
[22] making his rounds and walking around the bottom of his
[23] tank and everything. Came across a pair of glasses,
[24] reading glasses. And picked the reading glasses up and
[25] noticed that this was familiar to him, that it belonged

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[1] to the Koch gauger, you know. But where is this Koch
[2] gauger?

[3] And he got to looking and he looked up,
[4] and the Koch gauger was leaning over the catwalk. He
[5] had — he had died up there because of this exposure to
[6] this sour crude. It put several people in the hospital
[7] over the years with this stuff.

[8] Q: (By Mr. Lyon) Is there any question in your
[9] mind that the management individuals at Koch Industries
[10] knew that operation of a gas pipeline was a highly
[11] dangerous activity?

[12] A: Oh, yes.

[13] Q: Is there any question in your mind that they
[14] knew that?

[15] A: Oh, they knew this. Oh, yes. Oh, yes.

[16] Q: Now, why is the operation of a gas pipeline or
[17] an oil pipeline such a dangerous activity?

[18] A: Because of the hydrocarbon, the natural gas
[19] that's in it. I don't know what the flash point is. I
[20] can't remember what that thing is. But anything can set
[21] this — this thing off. You know, just working with the
[22] wrong tools can cause a spark or something or, you know,
[23] backhoe or something get into it or a bulldozer or even
[24] weather, lightning and things like that.

[25] Q: And yet you've told the jury in this case that

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[1] Koch Industries had no concern about safety around these
[2] pipelines. I want to know why you believe that.

[3] A: Because it affected our bottom line, impeded
[4] progress.

[5] Q: What do you mean by the bottom line?

[6] A: Profit, profit and loss.

[7] Q: Money?

[8] A: Money.

[9] Q: Greed?

[10] A: Yes.

[11] Q: Was Koch Industries, was their attitude toward
[12] making a profit such that they placed profit over human
[13] safety?

[14] MR. FAGELMAN: Objection, leading.

[15] Q: (By Mr. Lyon) In your opinion?

[16] A: Yes, yes.

[17] Q: Now, was — did you know Bill Caffey?

[18] A: Yes.

[19] Q: Was that his attitude about profit as the
[20] executive vice president or —

[21] MR. LYON: What is his title?

[22] MR. WOLF: Koch Industries.

[23] Q: (By Mr. Lyon) Executive vice president of Koch
[24] Industries?

[25] A: Yes. That came — that came all the way down

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[1] from the top. Everything was profit driven. Squeeze
[2] out the biggest profit you possibly could give them.

[3] Q: What about did they care about safety as
[4] opposed to cutting costs?

[5] MR. FAGELMAN: Objection, leading.

[6] A: I don't understand your question.

[7] Q: (By Mr. Lyon) That's not a very — very good
[8] question. I'll rephrase it.

[9] Was Koch Industries — if you could, tell
[10] us whether or not Koch Industries was more concerned
[11] about cutting costs than the safety of human life.

[12] A: Yes.

[13] Q: Now, I want to ask you about their business
[14] practices in regard to making more profit. Was it a
[15] practice of Koch Industries to steal oil?

[16] A: Yes.

[17] Q: And was that something that was encouraged for
[18] you to do personally?

[19] A: Yes.

[20] Q: How would you do that?

[21] A: Well, we're out there in the field. It's just
[22] like walking away leaving the cash register open, I
[23] guess. You were unsupervised. There wasn't any
[24] witnesses out there. You couldn't afford — the oil
[25] companies couldn't afford to have witnesses because that

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(1) would entail too many people and impede progress. These
(2) tanks are filling up all the time with crude oil, and
(3) you need somebody there.

(4) So anyway, we'd go out there and we'd
(5) shorten the gauge, the top gauge maybe by an inch or two
(6) or three, and then — then come up on the back gauge a
(7) couple two or three inches. And then we probably would
(8) add maybe anywhere from five to ten degrees on the
(9) temperature.

(10) And then your BS&W, let's say the tank
(11) would check out at two-tenths. We'd probably call it
(12) four, four-tenths, five-tenths of one percent. And then
(13) if the gravity was let's say 27 gravity, we'd drop the
(14) gravity probably by two full points which would drop the
(15) cost of the barrel down by about four cents a barrel.

(16) Q: All right. Now, explain that to me because I
(17) don't understand any of that. I understand cutting a
(18) gauge. You would shorten a gauge?

(19) A: On the top gauge.

(20) Q: On the bottom?

(21) A: On the top.

(22) Q: On the top?

(23) A: If you —

(24) Q: How would you do it?

(25) A: If you had 10 foot in the tank, Ted, you'd want

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(1) to call it nine foot eight.

(2) Q: Okay. But the gauge would be proper, the
(3) right —

(4) A: Oh, yeah.

(5) Q: — length?

(6) A: Yeah, yeah, yeah.

(7) Q: Okay. You'd just basically lie about it?

(8) A: That's right.

(9) MR. FAGELMAN: Objection, leading.

(10) Q: (By Mr. Lyon) Okay. And was this a practice
(11) that was encouraged and taught by the Koch Industries —

(12) A: Yes.

(13) Q: — management people?

(14) MR. FAGELMAN: Objection, form. Excuse
(15) me.

(16) A: Yes.

(17) MR. FAGELMAN: Objection, form.

(18) A: Yes.

(19) Q: (By Mr. Lyon) And they knew that you people
(20) who were gaugers at that time were doing that?

(21) A: Well, sure.

(22) MR. FAGELMAN: Objection, leading.

(23) A: They would come out over. You would — you'd
(24) take these run tickets. A run ticket is just like a
(25) check. That's what a gauger would write. At the end of

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(1) the month the producer would show up at Koch demanding,
(2) you know, what — what this run ticket had on it.

(3) So you take what you bought in the field
(4) and what showed up at the tank, at Koch's tank battery
(5) was more than what you purchased. So they had an over
(6) and short report.

(7) MR. FAGELMAN: Objection, nonresponsive.

(8) Q: (By Mr. Lyon) Now, you also said some other
(9) things. They would change the temperature?

(10) A: Yes.

(11) Q: What would that do?

(12) A: Well, it would — there's a shrinkage. You buy
(13) hot and sell cold. Let's say the tank might be
(14) 80 degrees. Well, you'd probably want to call that 85
(15) or maybe 90, you know. And then after the tank is
(16) pumped out, the tank might have lost two or three
(17) degrees, but you'd probably drop that maybe five or ten
(18) degrees. You see, if the tank would cool off. So this
(19) is — this is shrinkage. And that would probably
(20) represent probably about two to three barrels right
(21) there just in temperature.

(22) Q: Now, did any of the producers ever catch any of
(23) the Koch employees doing that that you know of?

(24) A: Yes. There was, you know, sometimes they
(25) would — they would question it and things. And they

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(1) would ask me, you know, What's the deal here, you know?

(2) And I'd tell them. Well, they said, Well, I had 10 foot
(3) in that tank when I topped that tank off this morning.
(4) I would say, Well, your tank was so hot it shrunk, you
(5) know, and stuff like this. And like I said, these
(6) people are busy, and so they would just kind of pass it
(7) off.

(8) Q: Now, did Koch have a practice of covering up
(9) leaks and spills?

(10) MR. FAGELMAN: Objection, leading.

(11) A: Yes, yes.

(12) Q: (By Mr. Lyon) Now, let me rephrase that. Do
(13) you have any information about Koch Industries'
(14) practices in regards to leaks and spills?

(15) MR. FAGELMAN: Objection, form.

(16) Q: (By Mr. Lyon) You can answer that yes or no.

(17) A: Yes.

(18) Q: And tell the jury what information you have
(19) about Koch's business practices concerning leaks and
(20) spills.

(21) A: Well, everything goes back to cost. If you had
(22) a spill or a leak, you wanted to get this thing taken
(23) care of with the least amount of dollars involved. And
(24) so a lot of times if it was out in a remote spot where
(25) nobody was around and stuff like that, they'd just take

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(1) a shovel or something — we're talking about a leak, a
(2) pipeline leak now — and just take a spade and just kind
(3) of spade it over and turn the — turn the soil over,
(4) something like this. Or if there wasn't anybody around
(5) we might get a — do a fax, a real fax — fix on this
(6) thing. We might set it on fire, you know, and stuff
(7) like this.
(8) Now, in the Marine division where we would
(9) have spills off of barges and the thing would hit the —
(10) hit the water, what we'd probably do, there's never
(11) anybody around and stuff, we'd probably wheel wash. And
(12) what we mean by that, we'd take the tug away from the
(13) barge and snug the barge up to the bank and hook up the
(14) engines. We had twin screw engines on this boat. And
(15) that puts out a tremendous wheel wash. You can't
(16) imagine. And we'd just kind of wash that thing on down,
(17) down the river, and kind of get it all mixed up and get
(18) it on — get it on its way.
(19) Q: What — what would a company — what were the
(20) regulations, what were they supposed to do?
(21) A: Well, we were supposed to notify the Coast
(22) Guard immediately and tell the Coast Guard where we were
(23) and our location and what had happened, how much — how
(24) many barrels we spilled and how the spill occurred.
(25) Q: Were you aware of any times when they spilled a

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(1) large amount of oil and they didn't notify the Coast
(2) Guard?
(3) MR. FAGELMAN: Objection, form.
(4) A: Yes.
(5) Q: (By Mr. Lyon) How much did they spill?
(6) MR. FAGELMAN: Objection, form.
(7) A: Several hundreds of barrels.
(8) Q: (By Mr. Lyon) Did Koch cover that up?
(9) A: Yes.
(10) MR. FAGELMAN: Objection, form.
(11) Q: (By Mr. Lyon) Was that a management decision
(12) to do that?
(13) A: Yes.
(14) MR. FAGELMAN: Objection, form.
(15) A: Because it's — it was the cheapest way to go.
(16) MR. FAGELMAN: Objection, nonresponsive.
(17) Q: (By Mr. Lyon) Why did they cover that up?
(18) MR. FAGELMAN: Objection, form.
(19) A: Because of cost. There was too much cost
(20) involved.
(21) Q: (By Mr. Lyon) Let's talk about safety of the
(22) pipelines themselves. I want to ask you some questions
(23) about that. Did — was Koch Industries concerned about
(24) the integrity of the pipeline such that they wouldn't
(25) break and burst and perhaps cause damage to someone?

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(1) MR. FAGELMAN: Objection, leading.
(2) A: No. I'll give you an example. The Bayou
(3) Bouillon pipeline system —
(4) Q: (By Mr. Lyon) Let me stop you right there. Do
(5) you have any examples that you can think of that would
(6) illustrate for the jury what you're talking about?
(7) A: Yes, yes.
(8) Q: And would you go ahead and give us that
(9) example.
(10) A: It was the Bayou Bouillon pipeline system.
(11) It's a system that's 54 miles long and strictly crude
(12) oil. Half of it is 6-inch. The other half is 8-inch
(13) pipeline. To get the numbers to fit, you have these
(14) AFE's and you do — you do your homework on these
(15) things, and you have to present this thing to Mr. Koch
(16) to show him that you can make money with this. So the
(17) lower cost, the bigger return he's going to get.
(18) So what they did on this Bayou Bouillon
(19) pipeline system to get this thing to fit real well, they
(20) went out and purchased Mexican pipe, the cheapest pipe
(21) they could find, and they put this in. And after
(22) putting this in — and I'm on one end of this pipeline
(23) deal. There they tell me how concerned they are about
(24) pressure because of the pipe — the integrity of the
(25) pipe is just not there. So be very, very careful on how

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(1) much pressure I put on the pipeline. And we couldn't
(2) exceed 1250 pounds.
(3) I had a pressure recorder chart, and that
(4) was something that I change once a week. It was a
(5) weekly chart recording the pressure, and that was the
(6) only thing we had on the pipeline. And you had — you
(7) had other systems pumping in there. You had the Bayou
(8) Blue system on there, they were injecting, and you had
(9) the Belle Rose facility injecting. So we had several
(10) different places. So pressure was a very, very big
(11) concern, and we did exceed that 1250 pounds a lot.
(12) And when we would, we'd just kind of —
(13) we'd grit our teeth and kind of turn our heads, you
(14) know, just hope to heck she held together.
(15) MR. LYON: We're going to have to take a
(16) break here just a moment.
(17) (Recess was taken)
(18) Q: (By Mr. Lyon) What was Koch's attitude in your
(19) area about flying the right-of-ways of these pipelines?
(20) MR. FAGELMAN: Objection, form.
(21) A: We never — really never did. The only time we
(22) would is after a new line would — would have been laid,
(23) and we'd fly it probably for the first six months
(24) because of the — the concern about these piston pumps
(25) driving this product and the vibration, the pipeline

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(1) working itself out of the ground. But after that, after
(2) we were convinced that that wasn't going to occur, that
(3) just — that completely stopped. We didn't have any
(4) visual or anything on the pipeline after that. The
(5) pipelines weren't maintained.

(6) Q: (By Mr. Lyon) Let's stop right there. Tell me
(7) about Koch's practices in maintaining the pipelines.

(8) A: Pipeline —

(9) MR. FAGELMAN: Objection, form.

(10) A: Pipeline — pipeline right-of-ways?

(11) Q: (By Mr. Lyon) Yes.

(12) A: They weren't maintained. We — that is going
(13) back to this one again. This Bayou Bouillon pipeline
(14) system, that pipeline system was put in May 1st, 1972,
(15) and the pipeline had never was cleared, treated or
(16) anything. There's got to be trees out there probably
(17) couple of feet in diameter on that thing. It's just
(18) completely overgrown.

(19) MR. FAGELMAN: Objection, nonresponsive.

(20) Q: (By Mr. Lyon) Now, you're aware or tell me if
(21) you are aware of the federal government regulations
(22) regarding notification of individuals living next to
(23) pipelines. Were you — are you aware —

(24) A: Yes.

(25) Q: — of those regulations?

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(1) A: Yes.

(2) Q: What was Koch's attitude during the years that
(3) you worked for Koch Industries concerning notification
(4) of individuals who lived close to pipelines?

(5) MR. FAGELMAN: Objection, form.

(6) A: We never did participate in letting the general
(7) public know.

(8) Q: (By Mr. Lyon) Was that a — was that a company
(9) practice that was endorsed by upper management?

(10) MR. FAGELMAN: Objection, form.

(11) A: Yes.

(12) Q: (By Mr. Lyon) Why? Why would they not notify
(13) people?

(14) A: Well —

(15) MR. FAGELMAN: Objection, leading.

(16) A: — trying to keep their business to
(17) themselves. Can we go back to that question?

(18) Q: (By Mr. Lyon) Sure.

(19) A: I was trying to get together with the city
(20) council in that area of St. James to let — at a city
(21) council meeting, and I was going to start notifying
(22) these people of that. And that never — that never
(23) materialized.

(24) MR. FAGELMAN: Objection, nonresponsive.

(25) Q: (By Mr. Lyon) Now, your personal experience

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(1) was — I want you to tell me about your personal
(2) experience with trying to notify people about pipelines
(3) going close to their homes.

(4) A: We don't have any. We never did.

(5) Q: You told me a minute ago about St. James
(6) Parish. You were trying to get with the city council
(7) about that. What happened in regard — why did you not
(8) get to carry that —

(9) A: It wasn't —

(10) Q: — out?

(11) A: It wasn't very supportive. Here you go again
(12) Koch trying to stay quiet with their business. Felt
(13) like you might be cross-examined or something like that,
(14) you know. And they talked about maybe it was a good
(15) idea, but maybe we need to get an attorney involved in
(16) it and stuff. And it just kind of got — it just never
(17) materialized.

(18) Q: In other words, you wanted to do something —

(19) A: Yes.

(20) Q: — to notify these people —

(21) A: Yes.

(22) Q: — about this dangerous pipeline going through
(23) their homes —

(24) A: Yes.

(25) Q: — or close to their homes —

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(1) A: Yes.

(2) MR. FAGELMAN: Objection, leading.

(3) MR. LYON: Let me just finish the
(4) question.

(5) Q: (By Mr. Lyon) In other words, you wanted to do
(6) something about Koch Industries' pipeline going through
(7) an area dangerously close to peoples homes and notifying
(8) them about the dangers of that pipeline; is that
(9) correct?

(10) A: That's correct.

(11) MR. FAGELMAN: Objection, leading.

(12) Q: (By Mr. Lyon) And Koch upper management
(13) squelched that?

(14) A: Yes.

(15) MR. FAGELMAN: Objection, leading.

(16) Q: (By Mr. Lyon) Okay. Now, I'm going to
(17) rephrase that question for you. Can you tell the jury
(18) about any instances of Koch Industries stopping you from
(19) notifying people about a dangerous pipeline next to
(20) their home?

(21) A: Yes. I was with the city council in St. James
(22) Parish.

(23) Q: What happened?

(24) A: I told them, This is what I'd like to do. We
(25) could get the word out at a city council meeting and

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(1) work with the city council on this. They felt like
(2) that — they were nervous about this. They wasn't
(3) comfortable with it. They were talking about maybe —
(4) it was a good idea but they wanted to send an attorney
(5) down just in case of some questions were asked and we
(6) might get ourselves in a little — in a lot of trouble
(7) and things like that. That never materialized after
(8) that.

(9) Q: All right. Now, I want to ask you some
(10) questions, ask you to assume certain facts to be true.
(11) Okay? Assume that an 8-inch LPG pipeline came very
(12) close to a neighborhood. The name of that neighborhood
(13) is Oak Circle and that neighborhood is located in
(14) Kaufman County, Texas. Assume that Koch Industries
(15) owned this pipeline and that it was built in the early
(16) 1980s. Assume that the coating on the pipeline was
(17) known by Koch to be faulty, known through a series of
(18) visual inspection from the mid '80s through 1995.

(19) Assume further that Koch knew that the
(20) pipeline had external corrosion. Assume that Koch knew
(21) it had external corrosion at the road crossing in
(22) that — that goes into that neighborhood on the pipeline
(23) where the pipeline crossed under the road. Assume that
(24) the pipeline in the area of that neighborhood had low
(25) cathodic protection readings beginning in 1982 and

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(1) continuing through 1996.

(2) Assume that the cathodic protection on
(3) this pipeline requires rectifiers and that the rectifier
(4) which was responsible for protecting the pipeline from
(5) corrosion at the neighborhood failed for a period two
(6) months in late '95 and more than five months in '96
(7) prior to October the 24th, 1996 due to a bad groundbed.

(8) Assume that many, if not all, of the
(9) residents in that neighborhood did not know the pipeline
(10) was there and did not know and were never educated about
(11) how to recognize and respond to a pipeline emergency.
(12) Assume that Koch did not provide pipeline safety
(13) educational information to most of the people in that
(14) neighborhood.

(15) Assume that the pipeline on August
(16) the 24th, 1996 was transporting liquid butane at
(17) pressures ranging from 1200 psi to in excess of
(18) 1440 psi.

(19) Assuming those facts to be true,
(20) Mr. Dubose, do you have an opinion whether it was
(21) reasonably certain that engaging in the conduct of
(22) operating that pipeline, transporting to — liquid
(23) butane at the stated pressures, would lead to a rupture
(24) and escape of the butane?

(25) MR. FAGELMAN: Object —

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(1) Q: (By Mr. Lyon) Do you have an opinion?

(2) MR. FAGELMAN: Objection, form.

(3) A: Yes.

(4) Q: (By Mr. Lyon) What is that opinion?

(5) A: That pipeline should have been abandoned.

(6) That — you had a hazard there.

(7) Q: And it's — would you — do you have an opinion
(8) as to whether or not it's reasonably certain that that
(9) would lead to a rupture?

(10) A: Sure, it would —

(11) MR. FAGELMAN: Objection, form.

(12) A: — yes.

(13) Q: (By Mr. Lyon) Assuming that butane escaped
(14) from the rupture right at that road, right at the road
(15) crossing, do you have an opinion as to whether or not it
(16) is reasonably certain that it could probably lead to the
(17) death of individuals who did not know how to recognize
(18) or respond to pipeline emergencies?

(19) A: Oh, yes.

(20) MR. FAGELMAN: Objection, form.

(21) A: Yes.

(22) MR. FAGELMAN: Objection, leading.

(23) Q: (By Mr. Lyon) What is — and your opinion is
(24) yes?

(25) A: Yes.

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(1) Q: And why? Why do you have that opinion?

(2) A: Well, the people weren't educated. Just a car,
(3) pickup truck, anything going by, any kind ignition
(4) source, pilot lights on hot water tanks, and, God, you
(5) just had — even atmosphere, lightning.

(6) Q: Do you have an opinion, sir, that a company
(7) that operates a pipeline in that situation, assuming all
(8) those facts to be true, is engaging in callous disregard
(9) for the rights and welfare of the people living close to
(10) that pipeline?

(11) MR. FAGELMAN: Objection, form.

(12) A: (By Mr. Lyon) Yes, they are.

(13) Q: And why is that, sir?

(14) A: Because they're not — they haven't maintained
(15) their equipment properly. They haven't notified or
(16) educated the residents along the pipeline. They
(17) haven't — they just haven't taken any kind of
(18) responsibility.

(19) Q: And sir, you worked for Koch Industries for
(20) 27 years?

(21) A: Yes.

(22) Q: You were a top manager in Koch Industries?

(23) A: Yes.

(24) Q: You dealt directly with the vice president and
(25) presidents of Koch Industries?

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(1) A: Yes.
(2) MR. FAGELMAN: Objection, leading.
(3) Q: (By Mr. Lyon) Do you have an opinion, sir,
(4) based on your years of experience, your education and
(5) training, your position within Koch Industries, that a
(6) company that operates a pipeline in that — in those
(7) situations that I gave you, that hypothetical, that it
(8) is reasonably certain that they will in all probability
(9) kill someone as a result of their gross negligent
(10) conduct?
(11) MR. FAGELMAN: Objection, leading.
(12) Objection, form.
(13) A: No doubt about it. There's no question.
(14) Q: (By Mr. Lyon) Do you have an opinion?
(15) A: Yes. This would kill somebody.
(16) Q: It's just going to happen?
(17) A: It's just when.
(18) MR. LYON: Okay. I want to take a break
(19) right now.
(20) (Recess was taken)
(21) EXAMINATION
(22) BY MR. MCCAULEY:
(23) Q: I'm going to ask you a few questions, and some
(24) of them may be to clear up some of the areas where there
(25) were objections earlier with regard to this

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(1) responsiveness and things like that, because we have to
(2) ask our questions in sort of a way that we can present
(3) them to the jury and we have rules that require that.
(4) A: Yes.
(5) Q: That's what is the basis for these objections,
(6) so I'm going to ask you some questions that may clear up
(7) some of the things I didn't understand in that area and
(8) may also clear it up for the jury.
(9) First let me ask you, tell the jury, if
(10) you would, what your training was in the area of
(11) market-based management when you were with Koch.
(12) A: The market-based management was to cut your
(13) costs right down to the bone so you could improve
(14) profits. That was the whole thing.
(15) Q: Where did you learn about market-based
(16) management?
(17) A: I learned it from — I first heard about it
(18) from Mr. Charles Koch.
(19) Q: And how did you learn about it from Mr. Koch?
(20) A: In meetings when he introduced market-based
(21) management.
(22) Q: Where were those meetings held?
(23) A: Wichita, Kansas.
(24) Q: Had you ever met Mr. Charles Koch before those
(25) meetings?

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(1) A: Yes.
(2) Q: How had you met him before that?
(3) A: Trips to Louisiana that he made. He made a few
(4) trips there. And then in meetings in Wichita.
(5) Q: Would these be, are you talking about
(6) management meetings or training meetings, or what kind
(7) of meetings were they?
(8) A: Yeah. We'd go to managers meetings and things
(9) like that, and he would kind of step in and duck his
(10) head in and out.
(11) Q: But he's the one that introduced for the first
(12) time market-based —
(13) A: Yes.
(14) Q: — management to you?
(15) A: Yes.
(16) Q: And then did you go through some market-based
(17) management training?
(18) A: Yes.
(19) Q: Where was that held?
(20) A: Wichita, Kansas.
(21) Q: When you say at Wichita, Kansas, are you
(22) talking about in that large black building located up in
(23) the north part of Wichita —
(24) A: Yes.
(25) Q: — Koch Industries headquarters?

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(1) A: Yes.
(2) Q: How many days did that training take?
(3) A: Overall, now, this is over — Mike, this is
(4) over a period of years. Now, this is probably couple of
(5) years.
(6) Q: Several different sessions —
(7) A: Yes.
(8) Q: — in other words?
(9) A: Yes.
(10) Q: All right. It wasn't just one session?
(11) A: That's right.
(12) Q: How did — if you would just for the jury,
(13) describe how, if at all, you saw market-based management
(14) actually put into practice or applied in the field.
(15) A: Well, market-based management was applied in
(16) the field by, you know, you cutting your costs. We had
(17) what we called — we had a tool that we called SPC,
(18) statistical process control, which it was graphing and
(19) charting. That was — consisted of run charts, parietal
(20) charts and control charts. And we started monitoring
(21) everything with these — with these — with these
(22) charts.
(23) Q: Would you tell the jury, please, in your job as
(24) a supervisor manager did you ever engage in or direct
(25) anyone else to engage in activities that were, you know,

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(1) extraordinary in order to bring your costs down, any
(2) kinds of extraordinary activities?
(3) MR. FAGELMAN: Objection, form.
(4) A: Yes.
(5) Q: (By Mr. McCauley) What kinds of things — if
(6) you'd tell the jury, please, what kinds of things did
(7) you do in order to bring your costs down that were
(8) outside the normal scope of business practice?
(9) MR. FAGELMAN: Objection, form.
(10) A: Clean like we spoke earlier, cleaning up these
(11) oil spills and leaks and —
(12) Q: (By Mr. McCauley) You mean —
(13) A: — not maintaining — not maintaining
(14) right-of-ways and maintaining pipeline systems properly.
(15) MR. FAGELMAN: Objection, nonresponsive.
(16) Q: (By Mr. McCauley) Are you telling the jury
(17) that in order to save money or save costs — you
(18) described it as cut costs to the bone a few minutes
(19) ago — that you didn't maintain the right-of-ways of
(20) your pipelines in a proper fashion?
(21) A: That's right.
(22) Q: What do you mean — tell the jury what you mean
(23) by that, not maintaining right-of-ways.
(24) A: We didn't maintain them. We didn't do
(25) absolutely anything to them.

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(1) Q: We're talking about down there in Louisiana,
(2) right?
(3) A: That's right.
(4) Q: Is this terrain like, for example, here in
(5) Texas we may have pastures that go on for miles and just
(6) wide open, no trees, nothing but short grass. Is that
(7) the kind of terrain we're talking about?
(8) A: No. More like a jungle-type terrain, and then
(9) we'd get out into the farming deal. We'd go through
(10) some cane fields and then river crossings and lakes and
(11) sometimes bays and sounds.
(12) Q: What were you supposed to do to maintain those
(13) right-of-ways?
(14) A: Oh, we should keep them cleared one — for one
(15) thing. Go out and hire an outside contractor to
(16) maintain these things. On a long line of 50 plus miles
(17) you'd probably get maybe there or four contractors and
(18) divide the line up between the contractors, you know,
(19) and tell them this is your responsibility here and to
(20) keep this area clean.
(21) Q: What was the purpose of maintaining the area
(22) around the right-of-ways?
(23) A: For visual deal that you could — you could
(24) detect leaks. And then — and then the public would —
(25) would see this out there in the middle of nowhere, this

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(1) just cleared area. They knew right away that this was a
(2) pipeline area.
(3) Q: Was it your understanding that you were
(4) required by law to maintain the right-of-way in a clear
(5) fashion so that it was accessible and observable?
(6) A: Yes.
(7) MR. FAGELMAN: Objection, leading.
(8) Q: (By Mr. McCauley) And why — why did — what
(9) was your understanding after your many years of Koch of
(10) why these rights-of-way were not cleared and maintained?
(11) A: Money. It was just — it was a question of
(12) money. It would take away from — from our profit
(13) margin.
(14) Q: What about if you couldn't — if the pipeline
(15) was a jungle around it, could you get to it and see it?
(16) A: Yes. You had to lay it.
(17) Q: I'm talking about afterwards when you were
(18) maintaining it. Was it accessible then once it wasn't
(19) maintained?
(20) A: When it wasn't maintained? No.
(21) Q: Well, how did you know whether or not if there
(22) were small leaks or if it was having problems?
(23) A: We didn't. There was just no way, unless the
(24) leak got so large where you would come up short.
(25) Q: So if you started having a shortage at the

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(1) receiving end —
(2) A: Yeah.
(3) Q: — then you would know you had a leak. But if
(4) it wasn't a large leak, you wouldn't know it?
(5) A: That's right.
(6) MR. FAGELMAN: Objection, leading.
(7) Q: (By Mr. McCauley) Well, did you-all fly these
(8) pipelines?
(9) A: We flew them for the first six months to — to
(10) satisfy us that the pipeline wasn't going to work out of
(11) the ground. And once we were satisfied that the
(12) pipeline was firmly entrenched, we quit flying it.
(13) Q: So during — how long were you a supervisor
(14) there at Louisiana? From what year to what year?
(15) A: Oh, from '81 to '94.
(16) Q: During that 13 years what was your experience
(17) with regard to whether or not Koch flew its pipelines?
(18) A: Never did.
(19) Q: What was your understanding about whether or
(20) not it was supposed to?
(21) A: Well, that's something that we should have
(22) maintained and government regulations to that effect.
(23) Q: You talked about cleaning up spills earlier. I
(24) heard you talking about putting — turning the boat
(25) around and turning the screws up to flush the oil.

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(1) During your years, let's say between '81 and '94 when
(2) you were in a supervisory role, did you have occasion
(3) to — to be involved in spills or leaks on Koch's
(4) pipelines or on their coastal facilities?

(5) A: Yes.

(6) Q: Did you ever have occasion to report to your
(7) seniors and supervisors the event of these pipelines and
(8) the volume of loss?

(9) A: Yes.

(10) Q: To whom would you report that?

(11) A: I'd report to Keith Langhoffer, Gary Baker, and
(12) Dan Shisler. Also reported to for a short time to Kyle
(13) Van.

(14) Q: Did you ever have any experiences where you
(15) actually reported to your supervisors what your estimate
(16) was or what you calculated to be the amount of loss in
(17) any spills?

(18) A: Yes.

(19) Q: Was that part of your job?

(20) A: Yes.

(21) Q: Can you give the jury any specific examples
(22) where you know whether or not the amount you reported is
(23) what got reported to the — in the leak reports and to
(24) the DOT, if required?

(25) MR. FAGELMAN: Objection, form.

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(1) A: No. They — they wasn't reported correctly.

(2) Q: (By Mr. McCauley) How —

(3) A: They was always underreported.

(4) Q: How do you know that?

(5) MR. FAGELMAN: Objection, form.

(6) A: Over the —

(7) MR. MCCAULEY: Excuse me. What is your
(8) objection?

(9) MR. FAGELMAN: Speculation.

(10) MR. WOLF: No. He knows it.

(11) MR. MCCAULEY: I don't want you to
(12) speculate. I asked him how does he know. Know is
(13) not — I didn't say what do you guess. That's what I
(14) consider to be a frivolous objection when I ask a man
(15) what he knows and you call for speculation.

(16) Q: (By Mr. McCauley) And you understand when I
(17) ask you what you know, I want you only to tell the
(18) jury —

(19) A: Yeah.

(20) Q: — what you actually know. I don't want you to
(21) be guessing and reaching out for grabbing —

(22) A: Yeah, yeah. There's no blue sky here.

(23) Q: Tell the jury, if you would, please, how you
(24) know that there was an underreporting that allows you to
(25) say that today.

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(1) A: Well, when I would report in to, let's say
(2) Keith Langhoffer or Dan Shisler, they would — they
(3) would keep the barrels down, down low not to attract any
(4) attention from the Coast Guard.

(5) Q: Well, did you ever —

(6) A: And —

(7) Q: — specifically tell anyone in response to
(8) reporting a leak what your estimate was of a leak?

(9) A: Yes.

(10) Q: Can you give a jury — the jury an example of
(11) what happened in that conversation?

(12) A: I reported a spill, and this was at Koch
(13) Marine. And there was a couple hundred barrels and they
(14) said they were going to keep that down to about
(15) 10 barrels.

(16) Q: Who said that?

(17) A: Dan Shisler.

(18) Q: What is Mr. Shisler with Koch as you know?

(19) A: Risk management.

(20) Q: What do you understand a risk manager or risk
(21) management to be?

(22) A: He was the one that we would notify in
(23) accidents and things like that. He would put these
(24) companies on notice that we were — that we were — God
(25) Almighty. Can't think of the word. Holding them

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(1) responsible for whatever happened, you know, in
(2) accidents and things like that.

(3) Q: And you reported to him in that instance how
(4) many barrels you estimated?

(5) A: 200 barrels.

(6) Q: And what was his response to you?

(7) A: That we were going to hold that down to about
(8) 10 or less.

(9) Q: Did you ever have any similar experience with
(10) anyone else or only him?

(11) A: Keith Langhoffer.

(12) Q: Give the jury an example of what happened
(13) with —

(14) A: That one.

(15) Q: — Mr. Langhoffer.

(16) A: This was at bayou — Mystic Bayou. We had a
(17) spill of probably about 450 — 50 barrels there. We
(18) happened to have a gauger on-site that gave the right
(19) number of barrels that hit the water in that incident.
(20) And I was in Wichita at that time. I had a meeting.

(21) The cost just kept escalating. Keith told me to get
(22) back to Louisiana and get that situation under control.

(23) Q: Okay. So you lost 450 barrels?

(24) A: Right. And when I got down there to meet with
(25) the Coast Guard, I told the Coast Guard that the barrels

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(1) Q: But why did you do that?
(2) A: To keep our costs down.
(3) Q: And why did you — why did you do that rather
(4) than tell the truth? What if you told the truth to the
(5) Coast Guard?
(6) A: Well, it would — he — if he was out there
(7) going to try to pick up these 450 barrels, he would have
(8) probably been out there a week or 10 days.
(9) Q: What would have happened, anything? If you had
(10) told the Coast Guard, if you had gone back down to the
(11) Coast Guard and said, Look, I agree with that gauger,
(12) it's 450 barrels and we'll clean it up, do you believe
(13) that based on your time at Koch that anything would have
(14) happened to you by way of repercussion?
(15) A: Oh, yes.
(16) Q: What would have happened to you?
(17) A: Probably gotten severely reprimanded. Probably
(18) maybe demoted or maybe completely terminated.
(19) Q: That other occasion when you said you talked to
(20) Mr. Shisler and told him that there had been a
(21) 200 barrel leak or spill and he said, well, we'll treat
(22) that as 10 or less —
(23) A: Uh-huh.
(24) Q: — was it your understanding at the time that
(25) he did that that the 10 or less was a false report?

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(1) A: Yes.
(2) Q: Why did you allow him to do that, make that
(3) change?
(4) A: Well, that was his call.
(5) Q: What was — and Mr. Shisler, where would he
(6) fall in the chain of command? Was he above you or was
(7) he be lateral, or what was he?
(8) A: Kind of a lateral, Mike. He represented, you
(9) know, risk managers — management for Koch Industries.
(10) Q: All over as you understood it?
(11) A: Yes, uh-huh.
(12) Q: Did you understand it to be his job to do that
(13) kind of reporting, to turn those numbers in?
(14) A: Yes, uh-huh.
(15) Q: Is that why you were reporting —
(16) A: Yes.
(17) Q: — to him?
(18) A: Yes. See, we had a certificate of insurance
(19) aboard these barges which you have to renew once every
(20) two years and — to be in compliance, and this is kind
(21) of like an insurance deal. That's the first thing the
(22) Coast Guard looks for when they come aboard your vessel
(23) to inspect. These barges inspected once a year.
(24) Actually twice a year. You had to — you have kind of
(25) like a walk-on inspection. You just kind of walk around

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(1) and look. And then — and then they want you to drag
(2) this thing out of the water every five years and check
(3) the integrity of the metal and everything.
(4) But you have what you call a certificate
(5) of insurance, and they want to see this thing to make
(6) sure if you have problems out there with — of a spill
(7) that there is money there to — to pick it up. And
(8) that — and the certificates of insurance always came
(9) from Dan Shisler.
(10) Q: Within your area of responsibility did that
(11) include being responsible for costs of operations?
(12) A: Yes.
(13) Q: Did you have any ways that you developed to cut
(14) costs in order to make your bottom line look better?
(15) A: Sure, yes.
(16) Q: Did you have any ways that you know in your
(17) mind were not legal or proper?
(18) A: Yes.
(19) Q: I want you to tell the jury what — what, if
(20) any, methods you used to cut costs in order to report a
(21) better bottom line to Charles Koch that you considered
(22) to be inappropriate in terms of legal or proper.
(23) A: Well, we went through it on maintaining the
(24) right-of-ways, putting money back into the pipeline
(25) systems.

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(1) Q: Say that — all right. What do you mean
(2) maintaining the right-of-ways?
(3) A: Clearing, clearing right-of-ways, maintaining
(4) pipeline systems, running smart pigs, checking for
(5) internal corrosion, you know, pumping chemical.
(6) Q: Are these all things you should be doing?
(7) A: Yes.
(8) Q: Were you doing them?
(9) A: No.
(10) Q: Well, what about smart pigs? During the time
(11) you were a supervisor did you all run smart pigs?
(12) A: We were getting ready to run one. We knew — I
(13) knew we needed to run one because of the integrity of
(14) the line was failing. We were getting numerous leaks on
(15) it. We were really scared of the pressure. And I told
(16) this to Wichita that we needed to run a smart pig. They
(17) asked me to get on it and run the costs by them. Told
(18) them the cost was somewhere in the neighborhood of
(19) \$30,000, and the thing stalled right there when I told
(20) them what price. The smart pig was never run.
(21) Q: Is that the same pipeline you talked about
(22) being made out of pipe from Mexico?
(23) A: Yes.
(24) Q: You said earlier that someone had told you to
(25) be careful with that pipe because — on the pressure

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(1) those operating pressures, was in fact turned in to your
(2) superiors?
(3) A: Yes.
(4) Q: It was done?
(5) A: Yes.
(6) Q: On a weekly basis?
(7) A: Yes.
(8) Q: Did any of your superiors ever say, Now, you've
(9) got to stop operating at ranges in excess of 1250 psi?
(10) Did anyone ever tell you to stop doing that?
(11) A: No. They knew we couldn't because we'd
(12) jeopardize the whole operation. We'd have to shut it.
(13) Q: Was that need discussed in terms of how you
(14) were working in your operation and the volumes? Was
(15) that discussed in your management meetings when you
(16) would meet with these guys above you that you were
(17) operating —
(18) A: No, no.
(19) Q: Was it discussed that you had increased — did
(20) everybody know that you had increased requirements, that
(21) you had more oil to ship than could be shipped at 1250?
(22) A: Yes.
(23) Q: Was there any question in your mind that
(24) everybody above you was aware of that?
(25) A: Yes.

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(1) Q: Yes, there is a question or no, there's not?
(2) A: Oh, yes. Everybody knew.
(3) Q: How do you know they knew?
(4) A: Oh, well, through reports. We had — we had a
(5) morning — a morning report that we would submit every
(6) morning from every field. They could tell by the number
(7) of barrels that was moved.
(8) Q: In addition to the pressure wheel —
(9) A: Yes.
(10) Q: — they could tell —
(11) A: Right.
(12) Q: — by the barrels?
(13) A: Yes.
(14) Q: You indicated that at least on two occasions
(15) you've described, one was your report to Mr. Shisler and
(16) the other was to Mr. Langhoffer, that leak information
(17) was incorrectly reported and on one occasion you
(18) actually indicated that you did that yourself with the
(19) Coast Guard down at Mystic Bayou.
(20) Do you know of any other instances during
(21) the time you were a supervisor or in a management
(22) position with Koch where information was recorded which
(23) was either incorrect or which was fictitious? In other
(24) words, if something wasn't done but a report was done or
(25) if something was done but the report wasn't accurately

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(1) made. Do you know of any —
(2) A: Yes.
(3) Q: — instances of that?
(4) A: Yes.
(5) Q: Would you tell the jury, just start and
(6) identify any instances you're aware of where that was
(7) done.
(8) A: Just on — just about on every spill we had,
(9) every spill or every leak. But mostly the spills in the
(10) Marine division wasn't reported accurately. They
(11) were —
(12) Q: But you're telling the jury that it was your
(13) experience that on almost every spill or leak you had
(14) the report of the actual leakage was not correct in
(15) terms of the amount or the volume that was leaked?
(16) A: Yes.
(17) Q: Was that done intentionally or accidentally,
(18) those —
(19) A: Intentionally.
(20) Q: Anything other than falsified or inaccurate
(21) reports of volumes of leakage that you saw while you
(22) were with Koch in a supervisory or management position
(23) where false or incorrect information was provided with
(24) regard to functions that had to be carry out — carried
(25) out by Koch?

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(1) A: I don't think I —
(2) Q: Well, for example, did you-all have to do
(3) inspections of your pipeline? Say, for example, were
(4) you supposed to take rectifier readings, pipe-to-soil
(5) readings, things like that?
(6) A: Yeah, through the smart pigs and things like
(7) that. That never got done.
(8) Q: Well, were the reports turned in?
(9) A: As — I'm sure there was. I didn't generate
(10) any reports. I think on this we had one guy taking care
(11) of all of our cathodic protection needs in those days.
(12) His name was Kenny Simms.
(13) Q: What was it?
(14) A: Kenny Simms coming from — he would come out of
(15) Duncan, Oklahoma. And we'd see him probably about once
(16) every year and a half or so. He'd come by and he'd take
(17) his readings, and he'd make his report. He never would
(18) really comment too much on what was going on, and he
(19) would leave. But we didn't have any cathodic protection
(20) people on-site. He came from Duncan, Oklahoma.
(21) Q: So the jury will understand, just give them as
(22) close to an understandable layman's explanation as you
(23) can so we can all understand, what is cathodic
(24) protection?
(25) A: Cathodic protection is a thing you use to

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(1) they were going to try to get Koch Gateway cathodic
(2) protection people to assume that responsibility; is that
(3) right?
(4) A: Yes.
(5) Q: But during the balance of your time there no
(6) one assumed that responsibility; is that correct?
(7) A: Nobody.
(8) Q: So are you saying between '92 and '94 there was
(9) nobody inspecting the pipeline in order to determine
(10) whether the — what cathodic protection was effective or
(11) not?
(12) A: That's right.
(13) Q: During the time that you were over that
(14) pipeline, did anybody ever come in and change out any
(15) groundbeds?
(16) A: No.
(17) Q: Is it your — did you have an understanding
(18) about whether groundbeds were permanent or whether they
(19) were designed to deplete and be replaced periodically?
(20) Did you understand one way or the other?
(21) A: No, I didn't know that.
(22) Q: You didn't know whether groundbeds —
(23) A: No.
(24) Q: — needed replacement?
(25) A: That's right. I didn't.

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(1) Q: Who did you rely on to make those kinds of
(2) decisions?
(3) A: Well, this Kenny Simms.
(4) Q: Who did you rely on between 1992 and 1994?
(5) A: I didn't have anybody.
(6) Q: Is there any question in your mind that the
(7) people above you, Mr. Martin, McCaleb, Caffey, Hannah
(8) and Koch, would have been aware that you didn't have a
(9) cathodic protection person for two years?
(10) MR. FAGELMAN: Objection —
(11) A: Yes.
(12) MR. FAGELMAN: — form.
(13) Q: (By Mr. McCauley) Do you have any reason to
(14) believe that the people above you were aware that you
(15) didn't have cathodic protection support between 1992 and
(16) 1994?
(17) A: Yes.
(18) Q: What reason do you have to believe that?
(19) A: Because there was no reports generated.
(20) Q: Because there were what?
(21) A: No reports generating.
(22) Q: No reports generated to your knowledge?
(23) A: That's right.
(24) Q: Well, and to your knowledge on your pipeline,
(25) no inspections were done between '92 and '94?

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(1) A: '4, that's right.
(2) Q: So if any reports were generated, they would
(3) not have been based on any actual physical inspection.
(4) Would that —
(5) A: That's right.
(6) Q: — be true?
(7) A: That's right.
(8) MR. FAGELMAN: Objection, leading.
(9) Q: (By Mr. McCauley) You testified earlier about
(10) this — the gauging practice. You're aware, are you
(11) not, of the — just through some method you're aware,
(12) are you not, about what's going on in Tulsa regarding
(13) lawsuits against Koch for stealing oil off of the Indian
(14) reservation? Are you aware of that?
(15) A: Yes.
(16) Q: How do you know about it?
(17) A: Through Roy Bell.
(18) Q: Okay. You know that the allegations are that
(19) the gauging wasn't done properly, don't you?
(20) A: Right.
(21) Q: Is it your understanding that the gauging
(22) techniques there were the same as the ones that you were
(23) talking about earlier that you-all applied?
(24) A: Yes.
(25) Q: Some people refer to that as the Koch method.

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(1) Have you ever heard of that?
(2) A: Yes.
(3) MR. FAGELMAN: Objection, leading.
(4) Q: (By Mr. McCauley) Have you ever heard of the
(5) Koch method?
(6) A: Yes.
(7) Q: What do you understand the —
(8) MR. FAGELMAN: Objection, form.
(9) Q: (By Mr. Fagelman) — Koch method to be?
(10) A: To get this oil in a good comfortable margin.
(11) Q: For the benefit of those of us who aren't in
(12) the oil business, tell the jury what the — what
(13) translated to real terms, what does that mean, in a good
(14) comfortable margin?
(15) A: Stealing.
(16) Q: So that if I understood earlier — and
(17) understand I've never done this. But if I understood
(18) you correctly earlier, what you do is if you change some
(19) of the elements that are involved — strike that.
(20) When you report how much oil you got, it's
(21) not just a matter of like at the gas station where you
(22) pump a pump and it goes into a can, you've got something
(23) that records. It's not that simple, is it?
(24) A: No.
(25) Q: If I understand what you said, you have to

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[1] actually measure the depth of the oil in the tank. Is
[2] that one thing?
[3] A: That's correct.
[4] Q: The temperature of the oil?
[5] A: Right.
[6] Q: The specific gravity of the oil?
[7] A: Right.
[8] Q: And other kinds of factors which go into sort
[9] of a formula, and that formula tells you what the volume
[10] of oil that you —
[11] A: Yes.
[12] Q: — took out of a tank was; is that correct?
[13] A: Yes.
[14] Q: If you underreport the depth, for example, if
[15] you reported it a foot lower in the tank than it was,
[16] that would — that would benefit Koch?
[17] A: Yes.
[18] Q: But it would cheat the person who owned the oil
[19] and was selling; is that correct?
[20] A: Yes.
[21] Q: Or if you reported the temperature as, for
[22] example, higher at the time that you took it out,
[23] then — well, excuse me. It was lower at the time that
[24] you took it out, then you would get a lower — it's like
[25] gasoline. If you pump gas on a cold day, you really get

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[1] more gas in your tank than you do on a hot day; is that
[2] right?
[3] A: Right. You want it to report hot.
[4] Q: You want to report hot because the air expands
[5] the oil?
[6] A: Right.
[7] Q: So you would report the temperature maybe three
[8] or four or five degrees higher, and that would actually
[9] reflect that you had gotten more oil than you actually
[10] took; is that correct?
[11] A: That's right. Because at the end — at the end
[12] of your closing gauge, if you had — if r you reported a
[13] 95 gravity — excuse me, 95 degree temperature and at
[14] the end of the run the tank was empty, you came back and
[15] you said the tank cooled off to 85, that's a 10 degree
[16] drop. And that would represent probably a couple, two
[17] or three barrels right there just in temperature.
[18] Q: So the end result of all that in that process
[19] using this Koch method, is that the amount of oil that
[20] you paid for to a man who sold it to you was in fact
[21] less than the amount of oil you actually took from him;
[22] is that correct?
[23] A: Right.
[24] Q: Is there any question in your mind that the
[25] gaugers you worked with and under your direction and

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[1] with you were aware that they were taking more than they
[2] were paying for for Koch?
[3] A: Yes.
[4] Q: Yes, there's a question or yes —
[5] A: Well, this is what was happening. Yes, we —
[6] Q: All right. Is there any question in your mind
[7] that the people you were working with were aware that
[8] was what was happening?
[9] A: Yes.
[10] Q: Okay. Well, let me ask the question
[11] differently. I said is there any question in your
[12] mind. Let me ask it differently.
[13] A: Oh, I'm sorry. Okay.
[14] Q: Did you believe — do you have reason to
[15] believe that the people you were working with, the other
[16] gaugers, were aware that this is what was going on, that
[17] you were paying for less than you were taking?
[18] A: Yes.
[19] Q: You described that as stealing earlier. Why do
[20] you call it that?
[21] A: Because we were taking something that really we
[22] didn't have coming.
[23] Q: Were you stealing for yourself or for Koch?
[24] A: For Koch Industries.
[25] Q: Do you have any reason to believe that the

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[1] supervisors above you were aware that that's how it was
[2] being done?
[3] A: Yes.
[4] Q: Why were you doing it that way?
[5] A: This is because this is the way we were
[6] directed. This is the way we were taught to purchase
[7] crude oil out in the field.
[8] Q: Do you know if that practice of gauging was
[9] still going on at the time you left Koch?
[10] A: Yes, it was still going on.
[11] Q: And you know that as a matter of personal
[12] knowledge?
[13] A: Yes.
[14] Q: That was in 1994?
[15] A: '94, yes.
[16] Q: Other than —
[17] A: Can I — can I —
[18] Q: Certainly.
[19] A: — add something —
[20] Q: Certainly.
[21] A: — to that deal? Probably around '92 when
[22] these allegations came out about Koch stealing oil and
[23] they know it was going to be publicized and everything,
[24] they started bearing down on us to kind of control it.
[25] They came out with what they called a control chart on

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[1] over and short. You know, they wanted to get it as
[2] close to zero as they possibly could.
[3] And we struggled with that and still tried
[4] to maintain to come out over. And we — we struggled
[5] with that for about a year, and then it just kind of
[6] faded. Then we went back to business as usual.
[7] Q: Was it — you said they wanted you to come out
[8] over. Was it a management expectation that the gauger
[9] come out over?
[10] MR. FAGELMAN: Objection, form.
[11] Q: (By Mr. McCauley) Were you expected to come
[12] out over? Were you —
[13] A: Yes, he was expected to come —
[14] MR. FAGELMAN: Objection, form.
[15] A: — out over, yes.
[16] Q: (By Mr. McCauley) Based on your experience
[17] with the company, could an employee, a gauger, continue
[18] to work for the company if he did not follow that
[19] practice?
[20] MR. FAGELMAN: Objection, form.
[21] A: No. No, he wouldn't have been allowed to stay.
[22] Q: (By Mr. McCauley) Have you ever heard of the
[23] concept that under market-based management that if you
[24] can't recover your investment within a certain time
[25] period, six months or nine months or whatever, that you

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[1] wouldn't want to make that expenditure?
[2] A: That's right.
[3] Q: Would you — I've heard that discussed, but I
[4] don't — I don't know exactly what the policy was.
[5] Would you tell the jury what the philosophy of
[6] market-based management was within — with regard to
[7] being able to recover your investment.
[8] A: Well, you want a return on investment as quick
[9] as possible. They gauged everything by eight percent.
[10] If you were doing eight — less than eight percent, felt
[11] like you were losing money. They felt like that you
[12] could take this asset and sell it and put it on a little
[13] simple interest rate, so with that amount of money
[14] involved would bring you an eight percent return. So
[15] everything was gauged on an eight percent.
[16] Q: So as the bottom line operating, eight percent
[17] return was the goal or better?
[18] A: Better than eight percent.
[19] Q: All right. Well, for example, did you have a
[20] budget to pay for things like fuel, truck parts,
[21] repairs, things like that?
[22] A: Yes.
[23] Q: How was that budget established?
[24] A: I — I would figure out the budget, and we did
[25] that for a number of years. Then all of a sudden that

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[1] stopped. Then Wichita started figuring out the budget,
[2] their accountants, and sending the budgets down.
[3] Q: When you say Wichita, are you referring to Koch
[4] Industries?
[5] A: Koch Industries, yes.
[6] Q: Would tell you here is sort of an expectation
[7] for this coming time period?
[8] A: Yes, uh-huh.
[9] Q: Did you ever do anything extraordinary, for
[10] example, to cut costs with regard to things like
[11] procuring the fuel or parts or things like that?
[12] MR. FAGELMAN: Objection, form.
[13] A: Yes.
[14] Q: (By Mr. McCauley) Strike that. Let me ask the
[15] question again so we don't have to worry about that
[16] objection.
[17] Please tell the jury how you — how you
[18] obtained supplies and materials that you needed —
[19] A: Out in —
[20] Q: — to operate your division.
[21] A: Well, out in the field when I was out in the
[22] field, what we did there, what I did there is to steal
[23] gasoline and diesel and lubricants from Atlantic
[24] Richfield to operate the pipeline and engines and pumps
[25] and the two boats and pickup truck.

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[1] Q: How did you do that? I mean, was it — they
[2] don't just have a pump out there, I guess. How did you
[3] do that?
[4] A: Yes. They had — they had a tank out there.
[5] Q: A diesel tank?
[6] A: A diesel tank and a gasoline tank.
[7] Q: Atlantic Richfield did?
[8] A: Yes, uh-huh.
[9] Q: How did you get access to it?
[10] A: By working there. I was out there about, you
[11] know, eight years, and everybody shared keys and
[12] everything.
[13] Q: So you're saying that gasoline was taken but
[14] never paid for?
[15] A: That's right.
[16] MR. FAGELMAN: Objection, leading.
[17] A: Gasoline and diesel.
[18] Q: (By Mr. McCauley) And diesel. When you say
[19] steal, I mean, that's what I'm asking. Does that — do
[20] you mean that it was never — they were never
[21] compensated for what you took?
[22] A: That's right. That's right.
[23] Q: How long did that go on?
[24] A: Two and a half years.
[25] Q: Why did you do that?

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[1] A: To cut costs.
[2] Q: Well, that wasn't for you personally, was it?
[3] A: No, no, no. This is all for Koch Equipment.
[4] Q: Like when you'd turn in your expenses, what did
[5] it show in the column for diesel or gasoline?
[6] A: Well, we — we had a report there to turn in,
[7] you know, on those expenditures, and a report was never
[8] generated.
[9] Q: You just didn't —
[10] A: I never sent a report in.
[11] Q: You wouldn't send a report in?
[12] A: Huh-uh.
[13] Q: And you were doing that in order to enhance
[14] your bottom line; is —
[15] A: Yes.
[16] Q: — that right?
[17] A: Yes.
[18] Q: If you didn't do that, would you have been able
[19] to meet the eight percent or better goal?
[20] A: I don't know.
[21] MR. FAGELMAN: Objection, form.
[22] A: I don't know. I was in — wasn't in charge of
[23] a P&L in those days.
[24] Q: (By Mr. McCauley) Well, why were you doing it
[25] then? What was the point in doing it?

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[1] A: It was to save — save Koch money.
[2] Q: Why did you feel a need to do that kind of
[3] thing, to save Koch money?
[4] A: Because it was expected of me.
[5] Q: By whom?
[6] A: By Koch Industries.
[7] Q: By that do you mean your supervisors?
[8] A: Supervisors, right.
[9] Q: And the people above you?
[10] A: Yes, uh-huh.
[11] Q: Is that — was that kind of practice unique to
[12] you, or do you have personal knowledge of whether or not
[13] that kind of thing was done by other people, other
[14] managers and other people?
[15] A: I know of one incident where a guy took a
[16] pressure chart, a whole — the whole chart, the whole
[17] thing from some other pipeline system and reinstalled it
[18] on Koch's system.
[19] Q: Do you know why he did that instead of just
[20] procuring one through Koch?
[21] A: Cut — cut costs. I was out in the field in
[22] those days, and Eric Erickson was the division manager
[23] in those days. And Koch had received a large quantity
[24] of water at the St. James terminal, and it was — and
[25] this water was purchased as crude. You know, also

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[1] water — you know, water isn't part of the equation.
[2] They had problems down at Bayou Blue. It
[3] was 1800 barrels of water showed up there. And so they
[4] need to replace this water with crude.
[5] Q: Let me stop you so I understand. 1800 barrels
[6] of filled — that were supposed to be filled with crude
[7] showed up —
[8] A: Yeah. Supposed —
[9] Q: — with water?
[10] A: Should have been crude oil but showed up as
[11] water, saltwater.
[12] Q: How did they get water in them?
[13] A: We had a gauger at our Bayou Blue field that
[14] wasn't doing what he should have been doing. He was
[15] intentionally pumping water into the system, calling it
[16] crude oil on a run ticket to satisfy the producer. The
[17] producer was also the well owner.
[18] Q: Then where — what would — what happened to
[19] that? I interrupted you right there. So then these
[20] barrels show up on the dock and what happens?
[21] A: Well, it's — you know, there's no market for
[22] saltwater, you know. So the gauger — the manager came
[23] down to me and said — and they knew I had a way to do
[24] it, to recapture 1800 barrels of crude oil.
[25] And they said, Phil, we want you to get

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[1] this crude oil down to St. James, these 1800 barrels, to
[2] make up the difference in this water. And I told them,
[3] I said, I can't do this all at one pop, at one time. I
[4] have to do it in a series, you know, of three — three
[5] installments, 600 barrels. And I'll notify you when
[6] these 600 barrels are coming so you can pick it up on
[7] your morning report. When you're over, those are the
[8] 600 barrels that I told you that was going to come over
[9] there.
[10] And what the deal was, Atlantic Richfield
[11] had two 3,000 barrel tanks out in the field. Now, this
[12] field is producing 4200 barrels a day. So 6,000 barrel
[13] storage isn't nothing out there, so you had to keep it
[14] moving. So from time to time we would — we had —
[15] well, we had a lack unit, and a lack unit meters the
[16] crude, just like a gauger in the field 24 hours. He
[17] goes through this what we call a lack unit. And also
[18] for every barrel that goes through the system that gets
[19] a drop of crude oil from that barrel, so we can tell
[20] what the gravity is and BS&W at the end of the month.
[21] Okay. We didn't have any electricity out
[22] there. We had a 235 KW generators, and a lot of times
[23] those generators would stall, and went on — and it
[24] would come on automatically. We had switches on a
[25] tank. When the oil would get to a certain level, it

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[1] would send a signal down to the generator. It would
[2] start the generator. The generator is running on
[3] natural gas. Then once the power source came on,
[4] produced power to the lack unit which the meter.

[5] But you had rain and things like that or
[6] something would go bump in the night. Then the thing
[7] wouldn't come on. And it would only grind for about 10
[8] or 12 seconds, and then a reset button would kick out.
[9] That was to save the starter. The starters on those
[10] things were 400, 450 bucks. So when you'd get there,
[11] you'd have all this oil stacked up in the mornings in
[12] the tank.

[13] And what you would do, I'd shut everything
[14] in. Then we had a regular pump powered by a 190
[15] Waukesha, running on natural gas. I'd fire that up,
[16] then work it by hand just like we were in the field.
[17] Gauge it, get a gravity and check it out and
[18] everything. And then turn this 190 Waukesha on and pump
[19] it across to Koch's 10,000 barrel tanks. They had two
[20] of them. So that means we opening valves at the bottom
[21] of their tank and all this.

[22] Well, what I would do when those things
[23] would happen, I'd shut their valves off and put a seal
[24] on that tank, and the seal was to indicate if anybody
[25] ever got into the tank if the seal was broken. But what

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[1] I would do, I wouldn't seal the seal all the way to lock
[2] it. You couldn't really tell it, you know. It's just
[3] kind of sitting on the thing.

[4] So what I would do, I said to get this
[5] 1800 barrels of crude oil, I would intentionally shut my
[6] generator. I wouldn't allow it to come on while I was
[7] there during the day, and let that oil stack up. At the
[8] same time I'm pumping out my two 10,000 barrel tanks to
[9] St. James. ARCO's people leave around 3:30 in the
[10] afternoon. Everybody's gone, so it just leaves me
[11] there.

[12] So what I would do then, I would shut down
[13] my pipeline pumps and everything, shut down all the
[14] valves, go back and take that seal that I had locked,
[15] pull that apart, open up the bottom of that tank, bypass
[16] the meters now and equalize because the oil in
[17] Atlantic's tank is higher than what's in Koch's over
[18] there. They're sitting not a foot apart behind each
[19] other. So what I would do, I would gravitate the tank.

[20] Q: Till they equalized?

[21] A: Equalized. And then you would say, well, ARCO
[22] would probably, you know, notice that because they would
[23] come up short. I said that's a lot of crude. 4200
[24] barrels a day, that's a lot of volume coming through.

[25] And then I'd probably mess around with

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[1] maybe a heater treater or something, make the heater
[2] treater dump to the pit like they had a malfunction.
[3] You know, that was kind of —

[4] Q: All right. Do I understand that's how you got
[5] the 1800 barrels of oil?

[6] A: That's how we did it all the time, Mike.

[7] Q: So that was just one instance?

[8] A: Yeah.

[9] Q: You're saying it happened other times, too?

[10] A: Oh, yes. Oh, yes.

[11] Q: So are you saying that you took 1800 barrels of
[12] oil on that occasion from Atlantic Richfield and they
[13] were never paid for it?

[14] A: That's right.

[15] Q: And who was it that told you you needed to get
[16] 1800 barrels of oil to replace that saltwater?

[17] A: That was Eric Erickson.

[18] Q: And what was Mr. Erickson at that time?

[19] A: He was a division manager.

[20] Q: For Koch?

[21] A: For Koch, yes.

[22] Q: How long did it take you to get that Atlantic
[23] Richfield oil over into Koch's barrels or replace that
[24] 1800 barrels?

[25] A: Ten or twelve days.

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[1] Q: But that happened on other occasions, too, that
[2] kind of thing?

[3] A: Yes. But it didn't involve saltwater, 1800
[4] barrels of saltwater.

[5] Q: But it involved taking oil —

[6] A: Yes.

[7] Q: — that wasn't yours?

[8] A: Yes.

[9] Q: Why in the world were you — I'll call it
[10] stealing. Was it stealing?

[11] A: Yes.

[12] Q: Why were you stealing oil from Atlantic
[13] Richfield?

[14] A: To — to enhance Koch's bottom line.

[15] Q: How do you feel about that today as you sit
[16] here?

[17] A: Oh, it's pretty — it's pretty terrible. I —
[18] I've never worked for another oil company besides Koch
[19] or gauged for another company. Knowing there was so
[20] many variables in crude oil that you can't actually
[21] gauge crude oil accurately and break even. There's just
[22] no possible way you're going to do it because there's so
[23] many variables. So in the back of my mind I'm thinking,
[24] well, everybody's got to do this but maybe not at — on
[25] the same level of volume that Koch Industries is doing

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(1) just told me.
(2) Q: What steps did you take in order to try to
(3) cut your operating costs while you were a manager or
(4) supervisor?
(5) A: What steps I took to cut —
(6) Q: Did you do anything — for example, I'm going
(7) to go back through the question you just answered and —
(8) A: Okay.
(9) Q: — you heard him object as nonresponsive.
(10) A: Yeah.
(11) Q: Because you gave us a lot of answer —
(12) A: Yeah.
(13) Q: — but it wasn't really in response to a
(14) question I had asked you, so I'm going to give you a
(15) chance to answer it —
(16) A: Okay.
(17) Q: — by breaking it down.
(18) A: Okay.
(19) Q: Please tell the jury, if you would, what, if
(20) any, steps you took to try to bring your operating costs
(21) down.
(22) A: By eliminating the maintenance department and
(23) going strictly with contractors.
(24) Q: All right. So did you in fact then eliminate
(25) your entire maintenance department?

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(1) A: Yes, I did.
(2) Q: What did you do in order to back that up and
(3) have some maintenance backup?
(4) A: I went out, and we hired contractors.
(5) Q: What was Koch's response to your terminating or
(6) eliminating your maintenance department?
(7) A: They were really proud of —
(8) MR. FAGELMAN: Objection, form.
(9) A: — proud of what I did because I eliminated so
(10) many people and —
(11) Q: (By Mr. Lyon) Did you get any kind of reward
(12) for it?
(13) A: Yes. An eight percent raise.
(14) Q: Now, did you maintain the right-of-ways?
(15) A: No.
(16) Q: Did anybody mow those right-of-ways on a
(17) regular basis?
(18) A: No.
(19) Q: Did anybody go in and cut trees down on a
(20) regular basis?
(21) A: No.
(22) Q: Based on your experience as a manager and a
(23) supervisor of many years for Koch Industries, can you
(24) ascertain the integrity of a pipeline and know whether
(25) you're maintaining it — know whether you're operating

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(1) it properly if you don't maintain your right-of-ways?
(2) A: No.
(3) Q: Why didn't you maintain your right-of-ways
(4) then?
(5) A: Cost. Cost was too high.
(6) Q: When you say the cost was too high, what do you
(7) mean?
(8) A: To get people out there to maintain these
(9) right-of-ways was just — it was — would be an ongoing
(10) program and just didn't — we just didn't have it. It
(11) was just too much cost involved.
(12) Q: Of what period of time between '92 and '94, for
(13) those two and a half years, did you not have a
(14) maintenance program at all where you maintained your
(15) right-of-ways?
(16) MR. FAGELMAN: Objection, leading.
(17) A: A year and a half.
(18) Q: (By Mr. McCauley) What, if anything, other
(19) than cutting out maintenance did you do to improve your
(20) bottom line?
(21) MR. FAGELMAN: Objection, form.
(22) A: On the trucking side I came out with triaxial
(23) trailers. In other words, instead an eighteen-wheeler
(24) can only load up to 80,000 pounds total. That's total
(25) combined weight, cargo, truck and trailer. That you're

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(1) allowed by DOT. But the State of Louisiana allows
(2) triaxial trailers which would let us load up to 88,000
(3) pounds, so this would eliminate trips into the field and
(4) equipment and things like that.
(5) I also went to sliding seats. This is
(6) trucks again. And that term is used, I had — at the
(7) time we had — a driver had his own truck,
(8) eighteen-wheeler, truck, trailer and everything. What I
(9) did, I went to a sliding seat program. One driver would
(10) drive the truck 10 hours. Another driver would drive
(11) 10 hours. What that did there for me, I eliminated a
(12) lot of my investment. And when you eliminate as much —
(13) I cut my investment in half.
(14) Q: (By Mr. McCauley) You mean by not having
(15) downtime on the trucks?
(16) A: Yeah. No — the truck itself. Each rig is
(17) probably right at \$100,000 plus. So if you had a
(18) 20-truck fleet and went to a sliding seat program, you
(19) know, you only have 10 trucks so you're eliminating
(20) 10 trucks. So that's an investment. So my return on
(21) investment on 10 instead of 20 trucks was just ungodly.
(22) My profits went right out of the ceiling.
(23) In the trucking industry the norm is
(24) single digit profits. I don't know why these people
(25) want to even truck. But I had a 23 percent. And that

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[1] was one of the biggest things I came up with, triaxial
[2] trailers that eliminated trips into the field. Plus I
[3] went to a sliding seat and eliminated a lot of my
[4] investment.
[5] Q: Did you ever know during the time you were with
[6] Koch of Koch being cited by any governmental bodies for
[7] any deficiencies or violations?
[8] A: Yes. DOT.
[9] Q: Tell the jury, please, what violations you're
[10] aware of that were originated from DOT for any actions
[11] of Koch.
[12] A: The action from DOT was overloading our
[13] trucks. It was the — the State of Texas was constantly
[14] citing Koch for being overloaded, in other words, over
[15] 80,000 pounds. And only thing Koch would do was just
[16] pay the fine and continue the practice of overloading
[17] the trucks. It was cheaper to pay the fine than not to
[18] overload the trucks.
[19] Well, the State of Texas after years of
[20] this caught on to what Koch was doing, so approached
[21] Koch and told Koch if they didn't stop what they were
[22] doing, they were going to brand them an habitual road
[23] damager and have Koch pay a certain percent of all the
[24] road repair in the state of Texas.
[25] MR. FAGELMAN: Objection, nonresponsive.

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[1] Q: (By Mr. McCauley) So what did Koch do when the
[2] State of Texas told them they were going to have start
[3] paying for a percentage of the road damage?
[4] A: We —
[5] MR. FAGELMAN: Objection, form.
[6] A: We cut the practice out.
[7] Q: (By Mr. McCauley) Meaning you stopped
[8] overloading the trucks?
[9] A: Yeah. We stopped overloading the trucks which
[10] meant more — more equipment in and —
[11] Q: More costs?
[12] A: Yeah, more cost.
[13] Q: Now, let me make sure I understand. I want to
[14] go back through that, and we'll break it down into parts
[15] like we did before.
[16] My question to you, I'm going to ask you,
[17] first of all, are you aware — and just tell me yes or
[18] no. Are you aware of any instances where Koch was cited
[19] with any deficiencies or citations by governmental
[20] agencies for violating what they knew to be lawful
[21] practices?
[22] A: Yes.
[23] Q: Would you tell the jury an example of where you
[24] saw that happen.
[25] A: It was in overloading our equipment,

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[1] overloading the trucks.
[2] Q: You mean putting more weight on them than the
[3] law allows?
[4] A: Yes.
[5] Q: Was that done intentionally by Koch?
[6] A: Yes.
[7] Q: How many pounds are those trucks allowed to
[8] carry?
[9] A: 80,000.
[10] Q: And what is the reason for that the State of
[11] Texas doesn't want trucks weighing more than 80,000
[12] pounds?
[13] A: It —
[14] MR. FAGELMAN: Objection, form.
[15] A: It damages their highways.
[16] Q: (By Mr. McCauley) You have experience in the
[17] trucking industry, don't you?
[18] A: Yes.
[19] Q: What is your background or experience in the
[20] trucking business?
[21] A: I've been the manager of Koch Trucking since
[22] 1986.
[23] Q: All right. Did you know that it was — based
[24] on your experience and training, did you know that there
[25] was a prohibition against loading the trucks in Texas

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[1] over 80,000 pounds?
[2] A: Yes.
[3] Q: And did you know that that was because if you
[4] did it would tend to damage the roads?
[5] MR. FAGELMAN: Objection, leading.
[6] A: Yes.
[7] Q: (By Mr. McCauley) Is that, for example,
[8] sometimes we drive down the highways and we get on these
[9] roads and they get real rough, and especially where you
[10] see a lot of truck traffic they get ripples in them and
[11] they get real heavy. Is that the kind of damage we're
[12] talking about?
[13] A: Yes, that and potholes.
[14] Q: So was it your experience that if caught
[15] violating, that tickets were given or citations?
[16] A: Citations.
[17] Q: And tell the jury, if you will, please, what
[18] Koch's policy or practice was during the time period
[19] when they were overloading the trucks. What was
[20] their — what was their policy with regard to that?
[21] A: The policy was —
[22] MR. FAGELMAN: Objection, form.
[23] Q: (By Mr. McCauley) If you know the policy, tell
[24] the jury.
[25] A: Was to — to just go ahead and pay the fine and

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[1] continue to overload the trucks.
[2] Q: Do you believe based on your experience and
[3] interaction with your supervisors that they were aware
[4] that overloading the trucks had the potential to damage
[5] the highways of the state of Texas?
[6] A: Yes.
[7] Q: And were those trucks overloaded with the
[8] consent and permission of your supervisors?
[9] A: Yes.
[10] Q: Did Koch at any point change this practice of
[11] intentionally overloading its trucks on Texas highways?
[12] A: Yes.
[13] Q: What brought about that change of practice?
[14] A: The State of Texas approached Koch Industries
[15] and told Koch if they didn't stop overloading these
[16] trucks that they were gonna brand them a habitual road
[17] damager and have them pay a certain percent of all the
[18] road repair in the state of Texas.
[19] Q: At that point did Koch change its practice?
[20] A: Yes.
[21] Q: Did it start complying with the law?
[22] A: Yes.
[23] Q: And why do you understand that they started
[24] complying with the law?
[25] A: Because it — if — it was told to me that

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[1] we're going to stop this practice and anybody who didn't
[2] was gonna — was gonna lose — lose a job.
[3] Q: And why did — what was the difference between
[4] being habitual and not being habitual in terms of what
[5] the result was to Koch?
[6] MR. FAGELMAN: Objection, form.
[7] A: Loading — overloading your trucks.
[8] Q: (By Mr. McCauley) No. What was the difference
[9] in the penalty that would occur, I mean?
[10] MR. FAGELMAN: Objection, form.
[11] A: The penalty? The difference in a penalty?
[12] Q: (By Mr. McCauley) Yeah. You said earlier they
[13] were giving tickets and later they were going to have to
[14] pay for a percentage of the highway.
[15] A: Yeah.
[16] Q: Did you understand whether it would have been
[17] more expensive to pay for a percentage of the highway or
[18] to pay the tickets?
[19] A: At that time when they said they were going to
[20] make us pay a percent of all the highway repair in the
[21] state of Texas. It would have cost us more money to —
[22] to continue that. We certainly didn't want to get
[23] involved in that.
[24] Q: Any other instances where you know where any
[25] governmental or regulatory agencies have cited Koch

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[1] during your experience and time there?
[2] A: Yes.
[3] Q: Tell the jury what that was.
[4] A: DOT.
[5] Q: And what was the circumstance?
[6] A: Overlogging.
[7] Q: What does that mean, overlogging? Just tell
[8] the jury what that means.
[9] A: Overlogging is when a driver — a driver by DOT
[10] can only drive — operate a truck 10 hours a day. And
[11] our drivers were driving exceeding those 10 hours; 12,
[12] 13, 14 hours a day.
[13] Q: Were these Koch employees that you're talking
[14] about?
[15] A: Yes.
[16] Q: Why were they exceeding the allowed 10 hours a
[17] day?
[18] A: Like I said, everybody had their own truck and
[19] they're — these are percentage drivers. They get 23
[20] and a half percent of the load. It's an incentive, get
[21] out there. In other words, more loads you bring in, the
[22] more money you make. And getting — and also getting
[23] the oil out of the field.
[24] Q: Was Koch management —
[25] A: Not —

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[1] Q: — aware that these drivers were exceeding 10
[2] hours a day?
[3] A: Yeah.
[4] MR. FAGELMAN: Objection, form.
[5] A: Because they have a log.
[6] Q: (By Mr. McCauley) You were Koch management,
[7] weren't you?
[8] A: Yes.
[9] Q: Did you see those logs?
[10] A: Yes.
[11] Q: Did others above you see those logs?
[12] MR. FAGELMAN: Objection —
[13] A: Yes.
[14] MR. FAGELMAN: — form.
[15] Q: (By Mr. McCauley) Do you know they saw those
[16] logs?
[17] A: Yes.
[18] Q: So Koch management then could look at the
[19] driver's log and see that a driver drove 14 hours a day
[20] or 12 or whatever; is that right?
[21] MR. FAGELMAN: Objection, leading.
[22] A: The deal was in those days you needed authority
[23] to operate a truck in the state of Texas, Louisiana,
[24] anywhere except I think in the state of Florida and
[25] Arkansas. And authority was a very delicate issue. If

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(1) education?

(2) A: Yes.

(3) Q: Tell the jury, please, what — who that was
(4) with. And if it was more than one we'll break it down.
(5) But at least, you know, for each instance where you had
(6) those conversations, tell the jury who it was with and
(7) describe the conversation.

(8) A: I had — I had a conversation with Tom McCaleb
(9) about public education and that I wanted to go in front
(10) of the city council of St. James and explain to them
(11) where these pipelines were and the dangers and make them
(12) aware of these — of this situation.

(13) It wasn't very well received. Koch felt
(14) like I might give out more information than I really
(15) should be giving out and maybe it would be best to maybe
(16) have an attorney do it or an attorney present. And
(17) that — that never happened. They never got back with
(18) me, you know, on any kind of direction.

(19) Q: Approximately when was that that you had that
(20) conversation with Mr. McCaleb?

(21) A: '94.

(22) Q: Any other instances other than that where you
(23) tried to get Koch to do some aspect of public education?

(24) A: No. I had asked them for a stress management
(25) course for our people, and they — they just didn't

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(1) think that — that — well, it didn't fly well at all.
(2) We were under extremely a lot of pressure. We were
(3) wearing two and three different hats and things like
(4) that.

(5) So what I did there, I went down to the
(6) Baton Rouge medical center. I can't remember the names
(7) now, but — but anyway, I visited with them and told
(8) them what the problem I was having, you know, with
(9) stress with our people. So I — I visit with them, and
(10) they would give me a few tips on — on what to do on
(11) handling stress that I could pass on to our people.
(12) Plus give us — gave me some little booklets for them to
(13) read on stress. And I'd pass it around the office and
(14) have everybody initial it.

(15) And then I had a superintendents meeting
(16) once a month. And in those meetings I always dedicated
(17) some time to stress management, to teach people how to
(18) handle stress better than what they were doing.

(19) MR. FAGELMAN: Objection, nonresponsive.

(20) Q: (By Mr. McCauley) As the division manager what
(21) was your view of why all this stress was happening?

(22) A: Because we were — we were overworked and
(23) pressure put on us, you know. Koch's attitude had
(24) changed towards people and it was, you know, our way or
(25) the highway type deal. You had to perform and that was

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(1) it, or you didn't have a job with Koch.

(2) Q: Let me go back and ask you something about
(3) leaks. You made a comment early to Mr. Lyon about the
(4) remedial action, the cleanup after a leak on the dry
(5) land, and you commented about sometimes they would just
(6) go out and light —

(7) A: Yes.

(8) Q: — the spill and let it burn off.

(9) A: Yes.

(10) Q: I didn't fully understand that. First let me
(11) ask you this question. When — did you have leaks while
(12) you were with Koch?

(13) A: Yes.

(14) Q: Was it your experience that those leaks were
(15) remedied, cleaned up and repaired, and all the steps
(16) were taken that should have been taken under the
(17) appropriate laws?

(18) MR. FAGELMAN: Objection, leading.

(19) A: Some were but most weren't.

(20) Q: (By Mr. McCauley) All right. Now, with regard
(21) to leaks, tell the jury if there are any examples of
(22) what you've just described as leaks that weren't
(23) properly cleaned up, what you mean by that. Tell the
(24) jury — tell the jury, if you would, an example of a
(25) leak that was cleaned up and how it was cleaned up where

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(1) you believe it wasn't done properly.

(2) A: The — we would clean it up ourselves. We
(3) had — that time we had our own maintenance department
(4) roustabouts, and they would come out. And if it was a
(5) lot of it standing, they might pump it off into a drum,
(6) then take a shovel and just turn the earth over and kind
(7) of out of sight, out of mind.

(8) Q: What did you understand was required to be
(9) done?

(10) A: Well, what we were — what we were really
(11) required to do was to pick it all up and bring it to a
(12) facility to have it treated, come back with fresh dirt,
(13) noncontaminated dirt, and fill in with that. Or take
(14) the contaminated dirt somewhere isolated and come up
(15) with what they call an air remediation program and let
(16) the air take care of it for so long.

(17) Then a guy from the State of Louisiana
(18) would come by and give you a good clean bill of health
(19) if he could, if the soil was —

(20) Q: Properly cleaned?

(21) A: Yes, uh-huh.

(22) Q: In this instance you've just described where
(23) the excess oil would be drawn off into a barrel and then
(24) the dirt would be turned, did that happen more than once
(25) or was that just one time?

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[1] A: Oh, that happened more than once.
[2] Q: When that happened did Koch notify any
[3] regulatory authorities of that spill and how they were
[4] cleaning it up and that method they were using?
[5] MR. FAGELMAN: Objection, form.
[6] A: Not to my knowledge. We — there was never
[7] anybody coming — would come out from any government
[8] agency like EPA or somebody like that to — to inspect.
[9] Q: (By Mr. McCauley) What I really want to know
[10] is, did Koch attempt to conceal the way in which they
[11] were cleaning up the spill?
[12] A: Yes.
[13] MR. FAGELMAN: Objection, form.
[14] Q: (By Mr. McCauley) What about this time when
[15] they — if it was more than one time you can tell the
[16] jury, but the time you told about where they burned off
[17] the excess. How did that happen?
[18] A: Well, we — that happened at our Bayou Blue
[19] facility. We had crude oil on the ground from a
[20] pipeline leak, and a decision was made by the field
[21] superintendent that, heck, we're not gonna play with
[22] this too much. We're gonna go ahead and set it on
[23] fire. And that's — that's what he did.
[24] Q: How many barrels are we talking about?
[25] A: Probably that one was probably about 20 or

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[1] 30 barrels. And we — it got out of hand and burned
[2] down a couple of power poles.
[3] Q: Fire got out of hand you mean?
[4] A: Yes.
[5] Q: Now, was that reported to any regulatory
[6] agency?
[7] A: No.
[8] MR. FAGELMAN: Objection, form.
[9] Q: (By Mr. McCauley) Why wasn't it reported to
[10] any regulatory agency?
[11] MR. FAGELMAN: Objection, form.
[12] A: Because there would have been costs, more costs
[13] involved.
[14] Q: (By Mr. McCauley) Are you — were you the
[15] supervisor or the district manager over the area where
[16] that happened?
[17] A: Not at that time.
[18] Q: Do you have personal knowledge that it was or
[19] wasn't reported to any agency?
[20] A: No.
[21] Q: Were you involved in the cleanup process in any
[22] way?
[23] A: No.
[24] Q: When did that spill occur, approximately?
[25] A: Probably 1980.

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[1] Q: Who was the field superintendent that made that
[2] decision?
[3] A: Raymond Robin, R-o-b-i-n.
[4] Q: Is he still with Koch?
[5] A: He's passed away.
[6] Q: In the time period between '92 and '94, were
[7] there spills that were cleaned up in a way that was not
[8] in compliance with regulatory requirements in the — on
[9] the pipelines that you were responsible for or on the
[10] shoreline facilities you were responsible for?
[11] A: Yes.
[12] Q: Approximately how many?
[13] A: Three.
[14] Q: Just describe the first one to the jury, if you
[15] will, please. First of all, where did it take place?
[16] A: It took place on the Bayou Bouillon system,
[17] Bayou Bouillon pipeline, and it took place in
[18] White Castle.
[19] Q: And what happened?
[20] A: We had a pipeline leak.
[21] Q: Approximately how much was leaked, if you
[22] remember?
[23] A: Probably about 20 — 20, 25 barrels.
[24] Q: And in what fashion was it not cleaned up in
[25] accordance with regulatory requirements?

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[1] A: It was just rather how I explained. They
[2] got — they picked up the oil they best they could and
[3] pumped it off into a tank, and then they just spaded
[4] over the — just turned the soil over.
[5] Q: And what's the second one?
[6] A: Was the same thing, Bayou Bouillon system about
[7] in the same area. All three of them, Mike.
[8] Q: In that same area?
[9] A: Yes, and treated the same way. This is when,
[10] you know, we had the smart pig deal and we were losing
[11] the integrity of the pipeline pretty rapidly.
[12] MR. FAGELMAN: Objection, nonresponsive.
[13] Q: (By Mr. McCauley) How much were the other two
[14] leaks approximately?
[15] A: I would say probably one — probably about
[16] 30 barrels, and other one I think was probably around
[17] 40.
[18] Q: Now, you described a situation where there
[19] would be a leak down or spill down into the water and
[20] turn around and backing the barge up and turning the
[21] screws up. Did that happen during the time you were
[22] district manager?
[23] A: A division manager?
[24] Q: I'm sorry. Division manager.
[25] A: For those two years? No.

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[1] Q: How do you know about it?
[2] A: It was reported to me. We did this when I was
[3] just a manager.
[4] Q: You were a manager?
[5] A: Of Koch Marine.
[6] Q: Okay. So you were in a supervisory role?
[7] A: Yes, yes. I was managing Koch Marine.
[8] Q: All right. Did this involve your area of
[9] management?
[10] A: Yes.
[11] Q: Okay. So you were the supervisor over that?
[12] A: Yes.
[13] Q: Did it happen more than once, or was it just
[14] one occasion?
[15] A: While I was managing Koch Marine?
[16] Q: Well, that you know of where they flushed oil
[17] on down the river or the bayou.
[18] A: Dozen plus.
[19] Q: A dozen plus times?
[20] A: (Witness nods head).
[21] Q: Approximately that one occasion you described
[22] approximately — or just take the one that was the
[23] largest leak or spill. Approximately how much would it
[24] have been?
[25] A: It was on — it was that on that Mystic Bayou.

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[1] Q: That 450 barrels?
[2] A: Yes.
[3] Q: And you're saying some of that 450 barrels was
[4] flushed on down the river?
[5] A: Oh, yes, yes. Before the Coast Guard —
[6] Q: Was that ever reported to the Coast Guard?
[7] A: No.
[8] MR. FAGELMAN: Objection, form.
[9] Q: (By Mr. McCauley) Any governmental agency?
[10] A: No.
[11] MR. FAGELMAN: Objection, form.
[12] Q: (By Mr. McCauley) Would you know if it had
[13] been reported? In other words, would it have been in
[14] your chain or responsibility —
[15] A: Oh, yes.
[16] Q: — to see?
[17] A: Yes.
[18] Q: So when you say it wasn't reported, you know
[19] that for a fact; is that right?
[20] A: Yes. Now, when you're asking me if it wasn't
[21] reported, flushing, yes, yes. That wasn't reported.
[22] That was something you shouldn't be doing.
[23] Q: That's not the kind of thing you report, is it?
[24] A: That's right.
[25] MR. FAGELMAN: Objection, leading.

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[1] Q: (By Mr. McCauley) It's not the kind of thing
[2] that they would take kindly to, is it?
[3] A: Yes.
[4] MR. FAGELMAN: Objection, leading.
[5] A: It would — you would be probably fined and
[6] maybe even jailed or — if they saw that going on.
[7] Q: (By Mr. McCauley) And you understood that
[8] there were penalties of some type associated with that
[9] kind of conduct when you did it, didn't you?
[10] A: Yes.
[11] Q: Why did do you that?
[12] A: Because it was expected of us because of going
[13] back to cost. We were trying to cut our costs the
[14] best — the best ways we could to keep that profit — to
[15] enhance that profit margin.
[16] Q: What happens to that oil when it gets flushed
[17] on down? Where does it go?
[18] A: Well, it disperses. It spreads out. And it'll
[19] cling to the river banks and, you know, to the soil and
[20] the water lilies and things like.
[21] Q: What about ducks and —
[22] A: Yeah.
[23] Q: — things like that?
[24] A: Fish. It will affect the fish. It'll kill.
[25] You'll have a fish kill and things like that.

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[1] Q: And were you and the other people above you
[2] aware of those kinds of consequences at the time that
[3] those actions were taken?
[4] A: Yes.
[5] MR. FAGELMAN: Objection, form.
[6] Q: (By Mr. McCauley) You were aware, weren't
[7] you? You were aware, right?
[8] A: Yes.
[9] Q: Who do you know of above you who was aware of
[10] that 450 barrel leak and actually flushing that down the
[11] river with a barge like that?
[12] A: Keith Langhoffer.
[13] Q: Did you tell him about it?
[14] A: Yes.
[15] Q: Was he ever there actually there on the site
[16] when it was going on?
[17] A: No.
[18] Q: So you just reported it to him?
[19] A: Yes.
[20] Q: Do you know whether he reported it to people
[21] above him?
[22] A: I don't know.
[23] Q: What was Mr. Langhoffer's position to you at
[24] that time?
[25] A: Vice president of Koch Service.

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[1] Q: You mentioned that you went up to Wichita
[2] several times for various meetings; is that right?
[3] A: Yes.
[4] Q: What types of meetings were these?
[5] A: Profit meetings, meetings to — they would
[6] address your P&L and look for ways to eliminate some
[7] costs and things that we should do.
[8] Q: You said that you met with Charles Koch and
[9] Bill Caffey; is that true?
[10] A: Yes.
[11] Q: Okay. How many times did you meet with these
[12] guys?
[13] A: Mr. Koch was introducing market-based
[14] management a lot, and I believe on four or five
[15] different occasions he was the one that was line driving
[16] this market-based management at meetings.
[17] Q: You never had any one-on-one meetings with
[18] Mr. Koch?
[19] A: No, no, not for any business.
[20] Q: So it was just a general type —
[21] A: Yes.
[22] Q: — seminar that he would —
[23] A: Yes.
[24] Q: — be giving?
[25] A: Yes.

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[1] Q: Okay. Same with Mr. Caffey. You never had a
[2] one-on-one meeting with Mr. Koch — Mr. Caffey?
[3] A: Yes, I've had one-on-one with Bill Caffey.
[4] Q: Okay. And when were these?
[5] A: Ninety — '93 and '94.
[6] Q: And where did these meetings take place?
[7] A: Wichita, Kansas.
[8] Q: And did Mr. Caffey call you up to Wichita?
[9] A: Yes.
[10] Q: Okay. And was there any particular reason why
[11] you went to Wichita?
[12] A: Yes.
[13] Q: And what was that?
[14] A: To — we were looking at ways to expand the
[15] Marine division. We had a study going and they — the
[16] Marine division was so profitable they thought we should
[17] add — add to the fleet. And so we were working on
[18] the — on the economics of putting two more boats and
[19] four — four or five barges to it.
[20] Q: Okay. You made a comment that Koch didn't have
[21] a concern for safety. Remember making some — a
[22] statement something like that?
[23] A: Yes.
[24] Q: Is that something that you felt, or were you
[25] ever told by someone at Koch, there's no reason for us

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[1] to look out for safety?
[2] A: No, Jason, they never come out and say that.
[3] But you could tell by their enthusiasm for it, and you
[4] had to struggle for everything that you were trying to
[5] implement as far as safety.
[6] Q: So again, this is just an impression that you
[7] had? No one ever said, Hey, Phil, let's don't do that
[8] because, you know, there's no need to be concerned about
[9] safety?
[10] MR. MCCAULEY: Objection, leading.
[11] A: Yeah. Nobody really after — but none of the
[12] programs got off the ground.
[13] MR. FAGELMAN: Objection, nonresponsive.
[14] Q: (By Mr. Fagelman) Did anyone ever tell you to
[15] disregard safety while you were at Koch?
[16] A: No.
[17] Q: You also mentioned something about shortening
[18] gauges and that that was a Koch practice?
[19] A: Yes.
[20] Q: You remember saying that?
[21] A: Yes.
[22] Q: Did anyone ever tell you, Mr. Dubose, go out
[23] there and shorten those gauges?
[24] A: Yes.
[25] Q: Who?

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[1] A: Oh, Joe Wade, Chuck Johnson, Doyle Barnett,
[2] Eric Erickson.
[3] Q: What did they — what did they say? What did
[4] Mr. Wade say to you?
[5] A: They would use their buzz words like, you know,
[6] get this oil in a good comfortable margin or we need
[7] some help on this — on this one. We're not doing —
[8] you know, we're coming up short. We need some help.
[9] Q: And you took that to mean shorten gauges?
[10] A: Yes.
[11] Q: But they never came out there and told you to
[12] shorten gauges, did they?
[13] A: No, they never did.
[14] Q: You also mentioned something about changing the
[15] temperature on some of the — I'm not too familiar with
[16] it. Shortening or changing the temperature —
[17] A: Yes.
[18] Q: — on the containers of gas?
[19] A: On crude oil.
[20] Q: Crude oil. Okay. And that was shrinkage?
[21] A: Yes.
[22] Q: Again, did anyone at Koch ever tell you,
[23] Mr. Dubose, go out there and change the temperature on
[24] those gauges?
[25] A: Yes.

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[1] Q: And who was that?
[2] A: That was Joe Wade.
[3] Q: And what did Mr. Wade say to you?
[4] A: Kept repeating the same thing year after year,
[5] buy hot, sell cold.
[6] Q: And you interpreted that mean — to mean go out
[7] there and change the temperature; is that true?
[8] A: Raise the temperatures, yes.
[9] Q: Okay. But at any time did Mr. Wade ever tell
[10] you to go out there and change the temperature or shrink
[11] the gas — shrink the oil?
[12] MR. MCCAULEY: Objection, form.
[13] A: Yes.
[14] Q: (By Mr. Fagelman) Mr. Wade told you to go out
[15] there and change the temperature?
[16] A: Yes.
[17] MR. MCCAULEY: Objection, form.
[18] Q: (By Mr. Fagelman) And Mr. Wade told you
[19] specifically to go out there and shrink the oil?
[20] A: Yeah. Change the temperatures, yeah.
[21] MR. FAGELMAN: Objection, nonresponsive.
[22] Q: (By Mr. Fagelman) Did he ever tell you to go
[23] out there and shrink the oil?
[24] MR. MCCAULEY: Objection, form.
[25] A: No.

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[1] Q: (By Mr. Fagelman) Now, you mentioned something
[2] about some spills and leaks. Was that your
[3] responsibility as division manager, to oversee leaks and
[4] spills?
[5] A: Yes.
[6] Q: Were you the only person in charge with regard
[7] to that at your company?
[8] A: Or the superintendents.
[9] Q: Okay. And who were they?
[10] A: Easley. Oh, God, I can't remember his first
[11] name. Last name Easley. And then Charles Addis, Danny
[12] Steele.
[13] Q: Now, were you over these guys or —
[14] A: Yes.
[15] Q: — were they above you?
[16] A: I was over them.
[17] Q: Okay. Now, you said that on several occasions
[18] these spills or leaks were not reported?
[19] A: Uh-huh.
[20] Q: Are you absolutely sure in every instance that
[21] these spills and leaks weren't reported?
[22] A: Not in every instance, no.
[23] Q: Is it possible that some of the leaks and
[24] spills that you don't believe were reported quite
[25] possibly were reported by someone else?

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[1] MR. MCCAULEY: Objection, form.
[2] A: I wouldn't know, Jason. I don't know.
[3] Q: (By Mr. Fagelman) So it is possible?
[4] A: Yes.
[5] Q: Now, do you know whether there's a certain
[6] level of spill that can occur that doesn't need to be
[7] reported?
[8] A: Yes.
[9] Q: Okay. So there is a base floor of barrels of
[10] gas or barrels of oil that need to be spilled before you
[11] have an obligation to report that to the DOT or the
[12] Coast Guard; is that true?
[13] A: Yes.
[14] MR. MCCAULEY: Objection, form.
[15] A: Yes.
[16] MR. FAGELMAN: What's your objection?
[17] MR. MCCAULEY: He's asked and answered the
[18] question at least twice. You've asked it twice. He's
[19] answered it twice.
[20] MR. FAGELMAN: So your objection is asked
[21] and answered?
[22] MR. MCCAULEY: Uh-huh.
[23] Q: (By Mr. Fagelman) You can answer the
[24] question. Do you want me to repeat the question?
[25] A: Is there a reportable quantity? Is that —

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[1] Q: Is there a minimum reportable quantity —
[2] strike that.
[3] Is there a minimum number of barrels of
[4] gas — of oil that can be spilled without a need to
[5] report that to the Coast Guard or to any other
[6] government agency?
[7] A: Yes.
[8] Q: So not every spill or leak needs to be
[9] reported?
[10] MR. MCCAULEY: Objection, form.
[11] A: That's right.
[12] Q: (By Mr. Fagelman) So some of the leaks and
[13] spills that you were discussing earlier today might have
[14] been leaks that didn't need to be reported in the first
[15] place?
[16] A: No. They all needed to be reported.
[17] Q: All of the leaks that we've discussed here
[18] today?
[19] A: Yes.
[20] Q: But again, some of those leaks might have been
[21] reported; you're just not sure?
[22] A: Yes.
[23] Q: You talked a little bit about public awareness,
[24] that you had made an attempt to go to the St. James city
[25] council. Did anyone at Koch ever tell you not to inform

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[1] the public?

[2] A: They told me not to attend the city council
[3] meetings.

[4] Q: Were you ever told by anyone in your —
[5] superior to you not to engage in any sort of public
[6] awareness program?

[7] A: No.

[8] Q: Is it possible that there was a public
[9] awareness program for your company?

[10] MR. MCCAULEY: Objection, form.

[11] A: There could have been. I wouldn't know.

[12] Q: (By Mr. Fagelman) So you're not — were you
[13] solely in charge of the public awareness program?

[14] A: I was in charge of the — of that whole area.
[15] In my area there wasn't.

[16] Q: And you're absolutely sure about that?

[17] A: Yes.

[18] Q: There's no doubt?

[19] A: That's right.

[20] Q: You were told not to attend the city council
[21] meeting, and that was by whom?

[22] A: Keith Langhoffer.

[23] Q: And Keith told you basically that we may want
[24] to have someone come down and attend that meeting on
[25] behalf of Koch; is that —

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[1] A: Yes.

[2] Q: Is that true?

[3] A: Uh-huh.

[4] Q: Okay. And your testimony is that that never
[5] happened?

[6] A: That's right.

[7] Q: Did you ever remind Keith about that?

[8] A: Yes, one time I did. I asked him about it.

[9] Q: And what did he say?

[10] A: He said, well, right now they were still
[11] thinking about it and right now that it wasn't being too
[12] received very well and that he would get back with me.

[13] Q: Okay. Did he say who wasn't receiving it very
[14] well?

[15] A: No. No, he didn't.

[16] Q: You talked a little bit about the market-based
[17] management program, that that was a way to try and cut
[18] costs to improve profits of the company.

[19] A: Uh-huh.

[20] Q: In any of the training seminars that you
[21] attended, was it ever stated by anyone at Koch to put
[22] profits above safety?

[23] A: Stated? No.

[24] Q: Did you ever at any time in your 26 plus years
[25] at Koch see any literature or document that in any way

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[1] suggested to you to put profits above safety?

[2] A: No.

[3] Q: You mentioned one particular spill of 450
[4] barrels and that that was reported to the Coast Guard
[5] and someone told you that we needed to limit that
[6] number; is that true?

[7] A: Yes.

[8] Q: And who told you that?

[9] A: Keith Langhoffer.

[10] Q: What exactly did he tell you to do?

[11] A: To get back down to Louisiana and get this
[12] thing resolved, get the Coast Guard out there and get
[13] this cleanup deal — resolve this cleanup deal as fast
[14] as I could.

[15] Q: And you took that statement to mean go down
[16] there and misrepresent the number of barrels spilled?

[17] A: Yes.

[18] Q: And that was your interpretation?

[19] A: No. We had talked about it.

[20] Q: Maybe you misunderstood my first question. My
[21] question was, did Mr. Langhoffer ever tell you
[22] specifically to misrepresent the number of barrels
[23] spilled to the Coast Guard?

[24] A: No. But he knew what I was going to do..

[25] MR. FAGELMAN: Objection, nonresponsive.

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[1] Q: (By Mr. Fagelman) Let me just ask it one more
[2] time. Did Mr. Langhoffer ever specifically tell you,
[3] Mr. Dubose, go down there and tell the Coast Guard that
[4] there were fewer barrels of oil spilled than actually
[5] were spilled?

[6] A: No.

[7] Q: At any time with any of these spills were you
[8] ever specifically told to lie to the Coast Guard or any
[9] other governmental agency by Mr. Langhoffer?

[10] A: Yes.

[11] Q: Which occasion was that?

[12] A: Oh, there was quite a few I recall. We didn't
[13] want to draw that much attention, and we wanted to try
[14] to get in there and try to clean it up ourselves with
[15] our own people to cut our costs.

[16] MR. FAGELMAN: Okay. I object to that
[17] answer as nonresponsive.

[18] Q: (By Mr. Fagelman) What did Mr. Langhoffer
[19] specifically tell you — give me one occasion when
[20] Mr. Langhoffer specifically told you to lie to the
[21] government or the Coast Guard about a spill.

[22] A: The one on Mystic Bayou.

[23] Q: And what did he specifically say to you?

[24] A: To get down there with the Coast Guard and work
[25] with them and get this thing resolved and do whatever I

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[1] had to do to mis — to get — to get this cleanup.
[2] Q: And you interpreted to get down there and speak
[3] to the Coast Guard and resolve this matter to mean limit
[4] the number of barrels, tell the Coast Guard that there
[5] are fewer barrels spilled than actually were spilled?
[6] MR. MCCAULEY: Objection, form.
[7] A: Yes.
[8] Q: (By Mr. Fagelman) And again, that was your
[9] interpretation, right?
[10] A: I told him what I was gonna do.
[11] Q: You told him — you told Mr. Langhoffer that
[12] you intended to lie to the Coast Guard —
[13] A: Yes.
[14] Q: — and tell them there were fewer barrels
[15] spilled than actually were?
[16] A: Yes.
[17] Q: You told him specifically those things?
[18] A: Yes.
[19] Q: And what did he say?
[20] A: Do what you have to do.
[21] Q: So if we went to Mr. Langhoffer and asked him
[22] about this incident, he would say, Yeah, that's what
[23] Phil Dubose told me?
[24] MR. MCCAULEY: Objection —
[25] A: Yes.

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[1] MR. MCCAULEY: — form.
[2] Q: (By Mr. Fagelman) Now, every time oil spilled
[3] you're not suggesting that Koch failed to clean it up,
[4] are you?
[5] A: No.
[6] Q: So there were many times when Koch actually
[7] cleaned up the whole spill; is that true?
[8] A: Yes.
[9] Q: More often than not?
[10] A: I would say — think so.
[11] Q: Now, as division manager at Koch Marine were
[12] you in charge of government compliance?
[13] A: No.
[14] Q: Who was in charge of that?
[15] A: I guess — probably Shisler, I guess.
[16] Q: So when you testified earlier today that Koch
[17] failed to comply with multiple federal regulations, that
[18] wasn't your department, right?
[19] A: No.
[20] Q: So you're not entirely sure how Koch complied,
[21] are you?
[22] A: Oh, yes, I'm sure.
[23] Q: How are you sure if it's not your department?
[24] A: Well, because of paperwork.
[25] Q: Okay.

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[1] A: All the paperwork was generated.
[2] Q: Are you suggesting that there was false
[3] paperwork suggest — generated?
[4] A: Yes.
[5] Q: Did you ever see paperwork filled out for
[6] certain inspections to be completed that was false?
[7] A: Probably in the Marine division, yes.
[8] Q: Are you saying probably or you did?
[9] A: You see, I really wasn't in charge of any of
[10] the paperwork deal. That was handled somewhere else.
[11] Probably — at Koch Marine, yes.
[12] Q: So in reality you're not sure whether Koch was
[13] in compliance or not because —
[14] MR. MCCAULEY: Objection —
[15] Q: — that's not your department?
[16] MR. MCCAULEY: Objection, form.
[17] A: No. I'm sure. I'll give you a deal like Koch
[18] Marine. You have to drag those barges out of the — out
[19] of the water once every five years, and the Coast Guard
[20] goes through them from stem to stern. You have the gas
[21] rim that go inside the compartments and everything. You
[22] have to take soundings of the — of the metal, and some
[23] of those soundings wasn't — wasn't correct.
[24] Q: (By Mr. Fagelman) Did someone under your
[25] direction fill out paperwork that would demonstrate that

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[1] those soundings were correct?
[2] A: Those things were filled out in the field. I
[3] guess it would probably be Milton Blanchard.
[4] Q: Did you ever with your own eyes see forms that
[5] you know were falsely filled out with regard to the
[6] situation you've just addressed?
[7] A: Yes.
[8] Q: And who filled those out falsely?
[9] A: It would be Milton Blanchard.
[10] Q: Did you tell Mr. Blanchard to fill those out
[11] falsely?
[12] A: No. That was just his — our way of taking
[13] care of business.
[14] Q: So —
[15] A: Keep from changing metal.
[16] Q: I'm sorry?
[17] A: Keep from changing metal.
[18] Q: So you instructed Mr. Blanchard to do that or
[19] not?
[20] A: No. It was something that was a practice there
[21] when we took over Koch Marine.
[22] Q: So that was a practice that existed before Koch
[23] ever got involved with this — this entity. Is that
[24] what you're saying?
[25] MR. MCCAULEY: Objection, form.

NO. 51458
IN THE DISTRICT COURT OF KAUFMAN COUNTY, TEXAS
86TH JUDICIAL DISTRICT

DANNY SMALLEY, INDIVIDUALLY AND AS INDEPENDENT
ADMINISTRATOR OF DANIELLE DAWN SMALLEY,
DECEASED, ET AL.
VS

KOCH INDUSTRIES, INC., KOCH PIPELINE COMPANY,
L.P., KOCH HYDROCARBON COMPANY,
KPL/GP, INC., AND RONALD GANT

REPORTER'S CERTIFICATE
DEPOSITION OF PHILLIP DUBOSE
July 9, 1999

I, Pam Durrant, a Certified Shorthand Reporter
in and for the State of Texas, hereby certify to the
following:

That the witness, PHILLIP DUBOSE, was duly sworn
by the officer and that the transcript of the oral
deposition is a true record of the testimony given by the
witness;

That examination and signature of the witness to
the deposition transcript was submitted on the 13th
day of July, 1999, to the witness or to the
attorney for the witness for examination, signature and
return to me by August 3rd, 1999;

That the amount of time used by each party at
the deposition is as follows:

Mr. Lyon/Plf Smalley 28 min
Mr. McCauley/Plf Estate 1 hr 46 min
Mr. Fagelman/Dfd 1 hr 15 min

That pursuant to information given to the
deposition officer at the time said testimony was taken,
the following includes counsel for all parties of record:

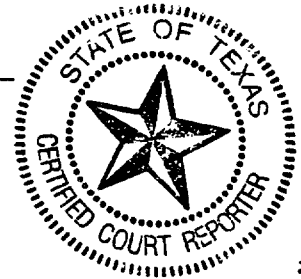
Mr. R. Michael McCauley, Attorney for the
Plaintiff, Estate of Danielle Smalley
Mr. Marquette Wolf, Attorney for the Plaintiff,
Danny Smalley
Mr. Jason Fagelman, Attorney for the Defendant,
Koch, et al.

I further certify that I am neither counsel for, related to, nor employed by any of the parties or attorneys in the action in which this proceeding was taken, and further that I am not financially or otherwise interested in the outcome of the action.

Further certification requirements pursuant to Rule 203 of TRCP will be certified to after they have occurred.

Certified to by me this 13th day of July, 1999.

Pam Durrant
PAM DURRANT, CSR 1746
FULLER & ASSOCIATES, INC.
1201 Elm Street
5260 Renaissance Tower
Dallas, Texas 75207



Charge for transcript and exhibits \$ _____
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23

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as)	
Trustee of the Prentice Dell Hamilton and)	
Florine Hamilton Family Trust)	
)	
)	Civil Action No. 9-01CV132
VS.)	
)	
KOCH INDUSTRIES, INC., Individually)	
and d/b/a KOCH HYDROCARBON)	
COMPANY, KOCH PIPELINE COMPANY,)	
L.P., KOCH PIPELINE COMPANY, L.L.C.,)	
GULF SOUTH PIPELINE COMPANY, L.P.,)	
GS PIPELINE COMPANY, L.L.C., ENTERGY-)	
KOCH, L.P., and EKLP, L.L.C.)	

AFFIDAVIT OF LINDA EADS

STATE OF TEXAS)
COUNTY OF DALLAS)

BEFORE ME, on this day personally appeared Linda Eads, who after being duly sworn stated as follows:

"My name is Linda Eads. I am beyond the age of 21 years. I have never been convicted of a felony or a crime involving moral turpitude and am otherwise competent to give this Affidavit. I have personal knowledge of the facts stated herein, and they are true and correct.

Professional Background

1. Attached to this affidavit is my *curriculum vitae*. By way of summary, I am a

tenured associate professor of law at Southern Methodist University, Dedman School of Law, in Dallas, Texas. I have taught at the Law School since January 1986. From January 1999 to August 2000, I was on leave from the Law School in order to serve as Deputy Attorney General for Litigation for the State of Texas. In this capacity, I supervised approximately 300 lawyers who handled all the civil litigation for the state. It was during this time that I supervised the State of Texas litigation against Koch Industries (Koch)--*United States and the State of Texas v. Koch Industries Inc. et al.* These cases were filed in the federal courts in Houston and Tulsa and involved crude oil spills by Koch Industries in Texas and other states. I also was directly involved in negotiating the settlement of these law suits in which Koch paid the highest penalty ever awarded under the federal Clean Water Act and agreed to injunctive relief aimed toward making its operation of crude oil pipelines conform to industry standards for safety, maintenance and reconditioning.

2. Prior to joining the law faculty, I served for eight years as a trial attorney for the United States Department of Justice, Tax Division. In that capacity I handled the prosecution of conspiracy and tax evasion cases as well as civil actions against promoters of fraudulent tax shelters. I graduated with honors from the University of Texas School of Law in 1975.

Documents Reviewed

1. While Deputy Attorney General, I reviewed much of the State of Texas file for the cases titled *United States and the State of Texas v. Koch Industries, et al*

filed in the federal courts in Houston and Tulsa. This included pleadings, discovery, depositions and memoranda related to these cases.

2. April 14, 1999 Deposition of Billy R. Caffey
3. July 9, 1999 Deposition of Phillip Dubose
4. December 15, 1997 Deposition of Garry Mauro
5. December 12, 1997 Deposition of John Lacy
6. December 29, 1997 Deposition of Saul Solomon
7. December 23, 1997 Deposition of Paul A. Montagna
8. August 26, 1999 Deposition of Gabriel Lugo
9. June 25, 1999 and July 1, 1999 Deposition of Edmond Raphael Murray, Jr.
10. July 1, 1999 Deposition of Kenoth Edward Whitstine
11. September 9, 1999 Deposition of Duke Mroz
12. September 28, 1999 Indictment of Koch Petroleum Group
13. September 28, 1999 Plea Agreement Between US and Koch Petroleum Group
14. September 28, 2000 Indictment of Koch Industries, et al.
15. January 11, 2001 Superceding Indictment of Koch Industries et al.
16. April 9, 2001 Plea Agreement Between US and Koch Industries
17. Consent Decree in United States and State of Minnesota v. Koch Petroleum Group
18. Order in United States *ex rel.*, William I. Koch v. Koch Industries, Inc. et al.
19. May 2000 GAO Report titled "The Office of Pipeline Safety Is Changing How It Oversees the Pipeline Industry"

20. August 11, 1999 NTSB Report on Pipeline Rupture at Lively, Texas on August 24, 1996
21. January 4, 1999 Opinion of Rimkus Consulting Group, Inc.
22. January 5, 1999 Opinion of Robert L. Harris
23. January 4, 1999 Opinion of Royce Deaver
24. January 4, 1999 Opinion of Jonathan S. Shefftz
25. January 4, 1999 Opinion of Devraj Sharma
26. Opinion of Lesa S. Adair
27. December 31, 1998 Opinion of Wesley Poynter
28. Introduction to Market-Based Management by Wayne Gable and Jerry Ellig
29. Web sites for the Environmental Protection Agency, the Office of Pipeline Safety and the Texas Railroad Commission
30. Sunset Report on the Texas Railroad Commission
31. Koch Industries Consolidated Financial Statements December 31, 1988 to December 31, 1996

Opinions

1. The business practices of Koch Industries, Inc., and its affiliated entities, make it highly probable that Koch's operation of natural gas and hazardous liquid pipelines exposes the plaintiff and the class members, as well as other members of the public, to risk of harm from Koch's failure to maintain and operate these pipelines in a safe manner as prescribed by various federal regulations.
2. In the recent past, federal and state government regulators and agencies have

not adequately addressed Koch's deficiencies in the area of pipeline safety and are unlikely to be able to do so in the future. This is a function of inadequate governmental resources as well as the limited oversight provided by the federal Office of Pipeline Safety and the Texas Railroad Commission.

3. Given these conclusions, it is my opinion that Koch's operation of Koch natural gas and hazardous liquid pipelines is likely dangerous, and action needs to be taken immediately to assess the condition of these Koch pipelines and recondition them as necessary. My experience in litigating against Koch teaches me that Koch will engage in dilatory practices that will delay the plaintiff and the class as well as the Court from receiving promptly the information needed to evaluate this danger. It is my opinion that a special master should be appointed to expedite discovery in this case.

How Koch's Business Practices Affect Pipeline Safety

1. In the course of supervising the litigation between the State of Texas and Koch Industries, I came to learn about Koch's history with regard to its pipeline operations, and I came to appreciate that Koch repeated its pipeline safety failures in many contexts. Because of my role, I had the unique opportunity to learn about Koch's behavior not only in the lawsuit I was supervising but also in a number of other cases involving Koch. From this, I was able to discern a consistent approach Koch had toward pipeline safety, maintenance and responding to pipeline problems. This approach comes down to a simple plan—Koch delayed making expenditures for as long as possible, even when

safety considerations clearly mandated such expenditures be made.

2. This approach gave Koch several options. It could run the pipelines hard until they were old and of little value. At that point the lines could become inactive or could be sold. In any event, Koch would have maximized its revenue from these pipelines without spending money to maintain them or repair the lines. Another alternative was to delay any repair until forced to make the repair either by government regulators or because the pipeline was inoperable without the repair. Again, this allowed Koch to maximize its profit since the dangerous and unrepaired pipeline continued to generate revenue without the expense of repair. And repair only occurred when it was mandated by government authorities or a faltering pipe. Therefore, Koch had use of the money it should have spent for repairs and maintenance all during the time it ignored making these repairs and maintenance. Given the time-value of money and the rate of return on money invested, Koch made a profit from its repeated decisions to delay implementing standard maintenance procedures and necessary repairs.
3. For purposes of this affidavit, I will focus on three major Koch pipeline leaks. These are: a) *Danny Smalley, et al. v. Koch Industries, et al* (a case involving teenagers who in 1996 burned to death in an explosion set off by driving a truck through butane gas that had leaked from a Koch pipeline. The jury awarded the plaintiffs \$296 million); b) *United States and the State of Texas v. Koch Industries, et al* (these cases that I supervised for the State of Texas involved over 300 crude oil leaks from Koch pipelines. Koch paid \$30 million in penalties

and \$ 5million to fund environmental projects– the largest penalty ever collected under the Clean Water Act); c) *Gum Hollow* crude oil spill in 1994 (this was one of the leaks involved in the cases discussed in item b. It is listed separately here because it was a very large spill pouring thousands of barrels of oil into the bay and estuaries around Corpus Christi.)

4. A consistent pattern became clear to me as I studied these three matters, a pattern that demonstrates that the leaks associated with these cases were attributable to Koch's business practices and business philosophy. In each of these three matters we see:
 - Koch pipeline corrosion causing the leaks;
 - Koch ignoring clear indications that the involved pipelines were experiencing corrosion problems and needed repair and maintenance;
 - Koch failing to provide proper cathodic protection or other corrosion protection for these pipelines; and
 - Koch failing to properly test the pipelines.
5. In the *Smalley* case the National Transportation and Safety Board (NTSB) found that the cause of the explosion was pipeline corrosion and that Koch had inadequate corrosion protection for that pipeline, notably that the cathodic protections levels were inadequate. The NTSB also concluded that Koch knew this but allowed it go uncorrected. Further, the evidence in *Smalley* established that Koch knew the pipeline had extensive corrosion and other significant problems, which it did not correct.

6. In *United States and State of Texas v. Koch Industries*, many of the leaks were found to have occurred under similar conditions as in *Smalley*. Koch knew that the pipelines had extensive corrosion and took no maintenance action to prevent or correct these problems or to cease use of corroded pipelines even though it was dangerous to continue such use without reconditioning the lines.
7. The *Gum Hollow* spill is an excellent example of this. In October 1994 Koch spilled thousands of barrels of crude oil into the Corpus Christi Bay area. To this day, the exact amount of crude spilled by Koch is unknown, but it has been estimated to be as high as 90,000 barrels. Koch initially reported the leak to be only 10 barrels, then eventually increased the volume of spill in increments from 400 to 500 to over 2000, although Koch's reporting did not approach the true size of the spill. This inadequate reporting of the volume of barrels spilled caused the Texas General Land Office to initially dedicate insufficient resources to clean up the spill. It is likely that the adverse environmental consequences from the spill were aggravated by Koch's inaccurate reporting. See deposition of Garry Mauro, in *Kevin Harms, et al. v. Koch Gathering Systems, Inc.*
8. The *Gum Hollow* spill demonstrates once again business practices by Koch that caused the pipeline to leak. Koch knew that the pipeline involved in that spill was in trouble, that it evidenced corrosion, that it was old, and that it needed to be examined. Koch had received in 1992 a recommendation that it test and examine that particular pipeline. This was not done. In fact just the opposite occurred. Koch did not test the line, and in 1994 it actually increased the

pressure on the line. Experts, such as John Lacey, have opined that Koch's failure to shut down this pipeline constituted gross negligence.

9. Further, once again the data indicated that the pipeline involved in the *Gum Hollow* spill was corroded, did not have proper cathodic protection, and that Koch was aware of these conditions.
10. From examining these cases as well as from knowledge I acquired when supervising the State of Texas litigation against Koch Industries, I have concluded that Koch recurrently does not repair its pipelines as necessary and that Koch commonly does not maintain its pipelines so as to reduce the likelihood of corrosion. For example, Koch often does not use proper cathodic protection or other industry-tested methods to prevent corrosion. Koch has a pattern of delaying needed repairs and maintenance, often neglecting them entirely. One reason for this failure to operate safe pipelines comes from Koch's so-called market-based management approach.
11. For example, under this management philosophy, each section of the Koch pipeline must show a profit, and this profit must increase in every quarter. Environmental and safety compliance does not pay off quarter by fiscal quarter, and thus employees are not rewarded or encouraged to strive for safety or environmental compliance. Indeed, safety improvements are regularly delayed or ignored even when recommended by employees. Employees at Koch are told that every decision has to be judged by its economic effect and how the decision will affect the company's profitability.

12. Koch's delaying or ignoring necessary safety improvements is confirmed by much of the evidence that I reviewed against Koch. Some of this evidence included the following:

a. I have reviewed the statements of Phillip Dubose who was a manager for Koch until 1994. Mr. Dubose testified that while he was with Koch and in charge of some pipeline operations, Koch did not follow recommendations to improve safety or institute proper maintenance procedures. Mr. Dubose also testified that Koch had poor pipeline maintenance, poor aerial coverage of the pipelines and poor public education and notification. Essentially, Mr. Dubose testified that managers knew that costs were to be "cut to the bone" and that safety and maintenance were not emphasized since they added to cost. It was notable to me that Mr. Dubose testified to underestimating a marine spill at Mystic Bayou in order to reduce the amount of scrutiny the spill would receive from the Coast Guard. He also testified that he did this at the direction of corporate superiors. This was significant to me especially in view of Koch's similar action of underestimating the marine spill at *Gum Hollow*, as discussed above.

b. This act of intentionally underestimating spills and leaks is similar to Koch behavior for which it was indicted in Texas. In January 2001, Koch Industries was indicted for conspiracy and making false statements to the United States Environmental Protection Agency and the Texas Natural

Resources Conservation Commission regarding the unlawful emission of benzene into sewers and streams in Texas. Koch eventually entered a plea of guilty to making false statements to these agencies, agreed to pay a fine of \$10,000,000 and was placed on probation for five years

c. Several Koch managers and corporate officials claimed their right under the 5th amendment when asked by lawyers I was supervising whether these Koch officials had ever intentionally understated spill volumes. Since the 5th amendment was asserted in civil litigation, it is acceptable for both a jury and this court to take notice of this assertion and draw the reasonable inference that these corporate officials indeed did understate spill volumes. It also is important to note the recurrent theme in these matters. Koch intentionally underestimated spills as seen in the testimony of Dubose and the assertion by corporate officials of the 5th amendment, and Koch intentionally made false statements to agencies that are regulating its behavior as seen in its guilty plea. This is not just negligent behavior. Koch's deliberate acts to falsify information important to safety considerations and environmental cleanup underscore its corporate approach to pipeline safety and makes it necessary to closely scrutinize Koch's operation of pipelines that carry dangerous substances.

d. I have reviewed the statements of Kenoth Whitstine, who also was a manager for Koch until 1994. Mr. Whitstine testified that he often could not receive approval for maintenance and safety needs from Koch

management. He testified that his experience with Koch was very different than his twenty-nine years experience with United Gas Pipeline. According to Mr. Whitstine, United Gas was much more willing to spend money on pipeline maintenance and safety. Mr. Whitstine also stated that a Koch corporate superior explained to him that the company had to look at that the cost of safety measures and evaluate whether it was economically better to pay for the safety measure or to pay damages in a lawsuit involving a pipeline accident.

e. These corporate decisions not to approve of needed maintenance and safety improvements described by Mr. Whitstine are similar to Koch behavior for which it was indicted yet again, this time in Minnesota. In 1999, Koch was indicted and entered a plea of guilty to various charges. In one count, Koch was charged with knowing that it was leaking between 200,000 and 600,000 gallons of aviation fuel and failing to take appropriate measures for several years to stop this fuel from reaching the Mississippi River. This again is an example of Koch not taking safety and environmental precautions in a expeditious manner, despite having knowledge of the leak or unsafe condition. In the same case, Koch also entered a plea of guilty to dumping millions of gallons of wastewater containing ammonia. Interestingly, Koch increased its flow of wastewater discharged into the Mississippi River on weekends when monitoring did not occur. Hence, the federal government charged that Koch took this

action to circumvent the monitoring and reporting requirements. In this plea agreement, Koch agreed to pay a \$6,000,000 fine and three years probation.

f. The incompatibility between Koch's management philosophy and pipeline safety is seen clearly by how Koch handled recommendations made in 1989 on leak prevention. In 1989 Koch established a leak prevention team. This team analyzed the causes of the pipeline leaks and established a four-phase remediation recommendation. These recommendations were not implemented, and the team was discontinued by Koch in 1990. Indeed, Koch delayed starting this implementation for seven years until 1996 by which time it had been sued by the United States, the State of Texas and private litigants. The cost of this remediation program was estimated to be \$98 million, a considerable amount indicative of the level of danger associated with the pipelines Koch was operating. It is my understanding that much of this remediation was not performed as Koch sold off a substantial amount of pipeline.

13. If one evaluated this company's performance using Koch's own market-based management approach, its system appears to have worked well. Koch was financially very successful during the same time it was leaking crude oil, butane, benzene and was falsifying reports to government agencies and circumventing reporting requirements. For example, from 1968 to 1994, Koch increased its revenue by 135%-- this during a time when the oil industry was in decline,

especially during the 1986 to 1994 period. In 1994, Koch had \$24 billion in revenue. Further, it is the second largest privately owned company in the United States.

14. Indeed, even in paying the largest penalty ever assessed under the Clean Water Act --\$35 million --Koch may have paid millions less than it actually gained from its decisions over the years not to make safety improvements to these pipelines. One economic expert in the State of Texas's case against Koch estimated that Koch saved over \$62 million dollars by failing to improve the pipelines that latter leaked and were the subject of the law suit. See Calculation of Economic Benefit, by Robert L. Harris. So under this calculation Koch profited by over \$25 million dollars by not making these pipelines safer even after paying a \$35 million penalty.
15. Koch's approach to delay pipeline improvement and reconditioning as long as possible appears to be continuing to the present. I say this based on the progress Koch has made in complying with the terms of the consent decree entered against it in *United States and the State of Texas v. Koch Industries, Inc.* This consent decree requires Koch to do a number of tasks to make its crude oil lines meet industry standards. The decree also requires that an independent auditor review Koch's progress toward implementing the terms of the decree and to make periodic reports on this progress. I have reviewed the most recent report by the auditor. This report states that Koch is in compliance with the time limits imposed by the decree, except for one. The auditor does not believe that

Koch will be able to meet the decree's time limits for assembling its risk assessment plan.

16. This delay in having a risk assessment plan is significant. Such a plan will provide an outline to Koch on how and when to repair its pipelines. Until the risk assessment plan is completed, Koch will be able to delay making repairs and taking other precautions, claiming that it does not want to commit large financial resources to repair of any particular pipeline until it knows which pipelines are most in need of repair. In other words, Koch will argue that it cannot triage the work it needs to do on its thousands of miles of pipeline until it has a completed risk assessment picture. Every day that Koch delays the completion of its risk assessment is another day it is able to keep the money for purposes other than improving pipeline safety. Obviously, the governments involved in this settlement are not going to ask the Court to find Koch in contempt based on a few months delay in Koch finalizing its risk assessment plan. So for Koch, there is no downside to avoiding the decree's time limit on this matter, provided it does not delay for so long a period that would trigger the government's negative reaction.
17. Further, it is puzzling that Koch is having difficulty completing this risk assessment since by the terms of the consent decree Koch is permitted to utilize data it may have from any prior applicable pipeline risk assessment. Koch began a major pipeline assessment and improvement project in 1996 and thus should have on hand data useful to completing this aspect of the consent

decree. This tends to confirm my impression that delaying the risk assessment aspect of the consent decree may be motivated by Koch wanting to delay as long as possible the large capital outlay that will be necessary to recondition these pipelines. This is in conformity with prior Koch financial practices that recognize the time-value of money and the economic benefit in delaying expenditures for as long as possible, even necessary ones.

18. While I have focused on three major cases or leak events and the Koch management approach that caused these pipelines to be in poor condition, other aspects of Koch's business practices also lead to my conclusion that these business practices likely expose the plaintiff and the class members, as well as the public, to a risk of harm. First, the experts that the State of Texas retained in its lawsuit against Koch concluded that Koch had inadequate training of personnel in matters regarding pipeline safety. This conclusion is confirmed by the statements of Koch managers, such as Dubose and Whitstine, who stated that Koch did not provide for sufficient training. Training is a key feature in adequate safety and maintenance, and its neglect increases the danger posed by Koch operating its pipelines.
19. Second, Koch has displayed a cavalier approach to record keeping on several occasions. This is troubling since so much of what we know about the condition of pipelines comes necessarily from the pipeline operators, themselves. Our national pipeline safety system is dependent on self-reporting, and governmental inspections are largely focused on the records supplied by the operators. A

company that fails to keep adequate records poses a danger under our self-reporting system of pipeline supervision. Koch has shown deficiencies in this area as established by the following:

a. In the State of Texas litigation against Koch, we found, and our experts confirmed, that Koch did not have adequate pipeline maps. The maps Koch submitted did not include required items such as the location of valves or the location of pressure safety devices. Further, Koch's records did not include diameter, grade, type and nominal wall thickness of its pipelines. Unbelievably, at one point in this lawsuit, Koch told the United States and the State of Texas that it did not have location maps of its pipelines and could not tell us where all the pipelines were.

Eventually, this was resolved, but it took some time.

b. In the State of Texas litigation against Koch, we brought a spoliation motion. While the judge did not find Koch intentionally destroyed documents, the judge did make the following findings of fact in 1998: (1) "Koch has not developed or implemented formal, company-wide information retention policies relating to the preservation of information for pending litigation or for other reasons." (2) "Koch has no formal information retention policies despite the fact that they have over 350 lawsuits pending at any given time." I would add to these findings that it is surprising that a company with self-reporting requirements and frequent dealings with state and federal regulators would not have a document

retention policy. To a pipeline operator concerned with complying with regulations and avoiding penalties, maintaining such records is important. Koch's inadequate record retention program reflects a different corporate attitude, an attitude focused on not making too much information available. This also argues for special supervision over the discovery process in this case, *Hamilton v. Koch Industries, Inc.*

c. In the State of Texas case against Koch, Koch's own expert claimed that Koch could not tell him which pipelines were active or inactive from 1989 to 1996. See deposition of Edmond Raphael Murray, Jr. This again demonstrates a corporation with poor records and little concern for accuracy.

20. Third, Koch placed unnecessary obstacles in the path of the State of Texas's litigation against it. I mention this here since I believe it demonstrates a corporate attitude that prefers to hide its operations. A few examples will explain this conclusion. Koch made it very difficult to obtain discovery unless we asked for documents from precisely the correct Koch entity that had the document requested even though all the entities were controlled by Charles Koch. This delayed discovery, and it was difficult to obtain a reasonable agreement with Koch on how to handle discovery when so many Koch entities were involved, and we had no way of knowing which entity had which record. Koch also claimed work product privilege for corporate records related to many of its spill and leak investigations arguing that the privilege applied because

Koch had sent lawyers to investigate the spills. This again delayed discovery.

21. I have concluded that this attitude of hiding operations and internal investigations or procedures is especially troubling when it is exhibited by an operator of pipelines carrying dangerous products. In this particular industry the public is best protected by full and complete candor and disclosure.
22. In the State of Texas litigation against Koch, over 300 oil spills were involved. During the course of this litigation, we conducted interviews, took depositions, looked at thousands of documents. This experience as well as learning about other cases against Koch leads me to firmly conclude that Koch's pipelines, whether carrying crude oil, natural gas, or hazardous liquids are in the hands of a company committed to a management approach that does not care much about safety and rewards only those who reduce cost and increase revenue. I fear for the consequences of this and am convinced that the relief requested by the plaintiff in this case is entirely appropriate and necessary.

Government Regulation and Oversight

1. A logical next question should focus on state and federal governmental regulation of these pipelines and why this regulation and supervision will not be sufficient to protect the plaintiff and the public.
2. The Koch management approach would lead to safety and environmental concerns no matter what level of governmental regulatory supervision was available to monitor Koch's activities. Even with a well-funded enforcement

program, Koch's management philosophy would lead to serious safety concerns. But the actual situation is much worse. The level of scrutiny that Koch faces is actually very limited due to a variety of factors, including : 1) inadequate oversight by the Office of Pipeline Safety and the Texas Railroad Commission; and 2) inadequate staffing and resources for enforcement. These inadequacies exist on both the state and federal levels.

3. In May 2000, the General Accounting Office issued a report that was highly critical of the federal Office of Pipeline Safety(OPS) with regard to its monitoring of natural gas and hazardous liquid pipelines. OPS is attached to the Department of Transportation, but it is small and has had a poor enforcement history. The GAO was particularly concerned that OPS was adopting a new regulatory approach without measuring the benefits of the new approach. This new approach will focus on risk management programs developed and implemented by pipeline companies and will reduce reliance on government regulation and enforcement. OPS believes this will increase safety and environmental protection. The GAO was critical that OPS was moving in this direction despite the absence of any demonstration that the new approach would produce the benefits of greater safety and environmental protection. Essentially, OPS is opting for a system in which the pipeline operators will review the condition of the pipelines and implement a risk assessment plan with the assistance of OPS. Penalties and enforcement actions will be reduced.
4. From 1990 to 1998, OPS had already reduced its enforcement actions so that

finances went from being assessed in 49% of its actions to being assessed in only 4% of its cases even though in that same period serious leaks and spills increased from 161 to 222. Moreover, OPS has only 55 inspectors nationwide. OPS is not an active enforcement agency. When this is combined with the fact that OPS has the lowest federal agency rate for implementing National Transportation Safety Board (NTSB) recommendations, it is unlikely in the future that OPS will engage in sufficient oversight to cause Koch to pay much attention to or expend significant funds for improving the safety and condition of its pipelines.

5. Some of the NTSB recommendations ignored by OPS deal with recurring pipeline issues important in this case. For example, the NTSB recommended in 1987 that OPS require operators to conduct periodic internal inspections of all pipelines to identify weaknesses and defects. OPS has refused to adopt this recommendation. OPS also has not adopted NTSB recommendations made in 1987 to ensure that operators are adequately trained to construct and operate pipelines and respond to emergencies. Thus the federal agency specifically charged with the task of ensuring pipeline safety is not particularly aggressive or dedicated to investigating the pipeline companies. Rather this agency is willing to rely on voluntary compliance and working in partnership with the operators. Indeed, almost all OPS inspections are announced in advance. This approach is unlikely to persuade Koch to behave in a manner more focused on safety than has been Koch's practice in the recent past.

6. The Environmental Protection Agency is also unlikely to play a large enforcement role in matters involving Koch. The EPA's focus is on implementing clean air, clean water and other environmental protection statutes and in developing regulations to meet the requirements of these statutes. Its mission is not to oversee pipeline safety. It is a regulatory agency and devotes little of its resources to enforcement. Its budget for 2001 reflected less than 1% for enforcement purposes. Therefore, on the federal side and in the federal regulation of interstate natural gas and hazardous liquid pipelines, it is unlikely that Koch will be subject to much enforcement activity from either OPS or EPA, especially on the issue of assessing the condition of its pipelines and reconditioning them as necessary.
7. The State of Texas has no authority over interstate pipelines and thus cannot be expected to oversee Koch's operation of the pipelines at issue in this case. At times in the past, however, the Texas Railroad Commission (RRC) has made recommendations to OPS regarding Koch's failure to meet pipeline standards. In my opinion, it is unlikely that the RRC will make frequent recommendations to OPS or will be aggressive in its audits and assessments of Koch's pipelines. I reach this conclusion for a number of reasons.
8. First, the Sunset Commission for the RRC issued its report in November 2000 and concluded that the RRC needed to improve its pipeline enforcement activities. The Sunset Commission concluded that the RRC does not have a consistent process for gathering information on pipeline safety or a consistent

penalty structure. The Sunset Commission was concerned that many pipelines are evaluated infrequently, but it noted that more evaluation and enforcement would be difficult since the RRC's Pipeline Safety Office has 46 employees, of which only 28 are inspectors. Moreover, enforcement activities have lacked coordination and supervision. The Sunset Commission recommended that an enforcement coordinator be added to the RRC's staff to give more structure and consistency to the RRC's enforcement work. As can be seen from this, the RRC has limited staffing and budget for its enforcement work. Moreover, the RRC's information gathering system has been less than optimal, and its penalty structure has not enhanced its enforcement posture.

9. One example will clarify the RRC's problems with its enforcement endeavors. In 1997, the RRC conducted an audit of Koch pipelines, and it submitted its evaluation to OPS on April 9, 1998. This audit found serious deficiencies in Koch's operations including many of the same problems discussed above such as unsatisfactory cathodic protection, unsatisfactory pressure testing, unsatisfactory line markers and a host of other failings. This audit was a significant endeavor by the RRC and appears to have raised serious questions about Koch's operations. Despite the fact that this RRC audit found significant deficiencies, Koch was assessed only a penalty of less than \$30,000 by the RRC and ordered to improve its operations. It is unlikely that a fine of under \$30,000 had any affect on Koch.
10. Moreover, the RRC initially refused to join with the United States Department of

Justice in suing Koch for its hundreds of oil spills in Texas. In 1995, prior to filing suit against Koch for violations of the Clean Water Act, the United States asked the RRC to join with it in this lawsuit. The RRC refused. Eventually, the RRC did refer spills to the Texas Attorney General's Office and did ask that these oil spills be used to join Texas to the United States government's action against Koch. This occurred in late 1997. However, the documents I have seen indicate that the Texas Attorney General's Office urged the RRC to refer these spills for litigation, and it was the Attorney General's Office that was instrumental in causing the RRC to join this lawsuit.

11. Further, when I assumed my duties at Deputy Attorney General in 1999 and began supervising this litigation, I asked the RRC to refer additional Koch oil spills to the Office of Attorney General to be added to the litigation. I knew we were entering the final phase of settlement negotiation, and I wanted to have as many state claims on the table as feasible. I thought this was prudent for the state so that we could settle as many damage claims as possible. I also thought this enhanced the State's settlement posture. I explained this to the RRC staff. Eventually, I was informed that the RRC had decided not to refer additional claims against Koch to the Office of Attorney General. I was never given an explanation about this decision.
12. From the preceding items, I conclude that it is unlikely that the RRC will be able to engage in a thorough and meaningful oversight of Koch pipeline activities within the State of Texas. The RRC does not have the enforcement resources to

do this and has not demonstrated the desire to bring actions or assess penalties against Koch that will cause the company to change its approach to safety and environmental protection.

13. It is the responsibility of the RRC to supervise pipeline safety in Texas. Other state agencies such as the General Land Office(GLO) or the Texas Natural Resources Conservation Commission(TNRCC) may occasionally have reason to assess the behavior of a pipeline operator and bring an enforcement action against pipeline companies. For example, the General Land Office has the responsibility to monitor spills in the coastal waters of Texas. In fact, the General Land Office was the Texas agency most active in assessing Koch's Gum Hollow spill discussed previously. However, neither one of these state agencies--the GLO or the TNRCC-- is likely to have much regulatory or enforcement activity involving the vast majority of Koch's pipelines.
14. Further, given the current fiscal condition of the State of Texas, it is highly unlikely that the State will commit significant additional resources to pipeline safety. The Texas State Legislature has imposed significant caps on the ability of state agencies to hire new personnel or give pay raises. Further, the Legislature has imposed significant limitations on the travel budgets of state agencies. This creates problems for state agencies, such as the RRC, that must send employees to locations throughout the state in order to conduct inspections, etc. I expect to see little change in the amount of government funds and resources the State of Texas devotes to obtaining compliance with pipeline

safety requirements or to taking action against those companies that are in violation of safety standards.

15. This preceding discussion leads to my conclusion that in the recent past federal and state government regulators and agencies have not adequately addressed Koch's deficiencies in the area of pipeline safety and are unlikely to be able to do so in the future. We thus are faced with the high probability that Koch is operating unsafe pipelines that carry extremely dangerous materials and that no governmental unit is adequately inspecting these pipelines, adequately addressing the problems associated with these pipelines or taking action to force Koch to recondition these pipelines. Without adequate governmental oversight and enforcement power, only lawsuits like this one are able to establish whether Koch's natural gas and hazardous liquid pipelines are dangerous and need immediate repair.

Need for Expedited Discovery and a Special Master

1. It is my opinion for the reasons advanced previously that Koch is likely operating unsafe pipelines and that government regulators and enforcers are unable to adequately redress this situation. It is important to discover the condition of these pipelines as soon as possible. It is my opinion that the Court should impose an expedited discovery schedule in this matter.
2. Because of the possible danger to the public as well as the plaintiff class, it is important that discovery delays be avoided. My prior experience with Koch leads me to conclude that it will engage in dilatory discovery tactics. To avoid

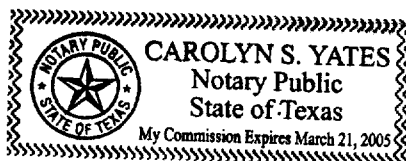
this, it is my opinion that a special master be appointed in this matter to ensure expedited discovery."

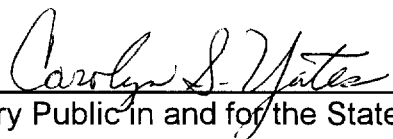
FURTHER AFFIANT SAYETH NOT


Linda Eads

STATE OF TEXAS §
 §
COUNTY OF DALLAS §

SUBSCRIBED AND SWORN TO before me by the said Linda Eads on the
25th day of September, 2001.




Notary Public in and for the State of Texas

My Commission Expires:

March 21, 2005

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EMPLOYMENT

August 2000- present	Associate Professor of Law, Southern Methodist University, Dedman School of Law Dallas, Texas
January 1999-August 2000	Deputy Attorney General for Litigation, State of Texas, Austin, Texas. In this position, I supervised the eleven civil litigation divisions of the Texas Office of the Attorney General. These divisions, with over 500 employees, handled matters ranging, for example, from bankruptcy to environmental pollution; from construction contract disputes to appeals to the United States and Texas Supreme Courts.
August 1991-January 1999	Associate Professor of Law, Southern Methodist University School of Law, Dallas, Texas.
January 1986-August 1991	Assistant Professor of Law, Southern Methodist University School of Law, Dallas, Texas.
October 1983-October 1985	Senior Trial Attorney, United States Department of Justice, Office of Special Litigation, Tax Division, Washington, D.C. (litigation involving abusive tax shelters).
October 1977-October 1983	Trial Attorney, United States Department of Justice, Criminal Section, Tax Division, Washington, D.C. (prosecutions and grand jury investigations involving violations of the

Internal Revenue Code and Title 18 of the
United States Code.)

October 1975-October 1977

Staff Attorney, District of Columbia Superior
Court, Washington, D.C.

PROFESSIONAL AWARDS

Southern Methodist University School of Law Don Smart Directed Research Award	1993
Southern Methodist University Scholar/Teacher of the Year	1991
Southern Methodist University Golden Mustang Teaching Award	1989
Southern Methodist University School of Law Don Smart Teaching Award	1989
United States Attorney General's Special Commendation Award	1983
Outstanding Attorney Award, United States Department of Justice	1981, 1984

BAR MEMBERSHIPS

Texas	1975	
District of Columbia		1976
United States Court of Appeals (5 th and 7 th Circuits)	1982	
United States District Court for the Northern District of Texas	1982	

COURSES TAUGHT

Constitutional Law
Criminal Tax Fraud
Evidence
Lawyering
Professional Responsibility
Trial Advocacy
Women and the Law

PUBLICATIONS

Getting It Right: The Trial of Sexual Assault and Child Molestation Cases under Federal Rules of Evidence 413-415, 18 **BEHAVIORAL SCIENCES AND THE LAW** 169 (2000) (coauthored with Daniel Shuman and Jan DeLipsey).

Betty Crocker or Barbara Jordan: Limited Roles for Women and the Effect of Reproductive Technology on Motherhood, **TEXAS JOURNAL OF WOMEN AND THE LAW**, Spring 1998.

Making a Federal Case Out of Crime Has More to Do with Playing Politics than Increasing Safety, **SMU MAGAZINE**, Winter 1995.

The Imprisonment of Commercial America, 27 **THE BRIEF** 8, Fall 1994.

From Capone to Boesky: Tax Evasion, Insider Trading and the Problems of Proof in Between, 79 **CAL. L. REV.** 1421 (December 1991).

Separating Crime from Punishment: The Constitutional Implications of United States v. Halper, 68 **WASH. U. L.Q.** 929 (December 1990).

Rambo in the Courthouse: Reasonable Solutions, 22 **THE BRIEF** 12 (Fall 1989).

Adjudication by Ambush: The Federal Government's Use of Nonscientific Experts in a System of Limited Discovery, 67 **N.C.L. REV.** 577 (March 1989) (article's recommendation that the Federal Rules of Criminal Procedure be amended was adopted in part by the United States Congress and is cited in the Advisory Committee Note to revisions to Federal Rule of Criminal Procedure 16).

PROFESSIONAL ACTIVITIES

Member, Texas Supreme Court Rules Advisory Committee	1999- present
Member, Faculty Advisory Committee to the Maguire Center for Ethics and Public Responsibility	1995-present
Faculty, Southwestern Medical School, First Year Clinical Medicine course (with focus on professional ethics)	1994-1998
Member, ABA Committee on Rules of Criminal	

Procedure and Evidence	1988-present
Director, National Institute for Trial Advocacy (NITA), Southern Regional Program	1989-91
Director, Dallas Bar Association Trial Skills Course	1989
Faculty, National Institute for Trial Advocacy–Southern and Pacific Regionals	
Faculty, Emory University School of Law Trial Skills Course	1994, 1997
Chair, Southern Methodist University President's Commission on the Status of Women	1988-90
Program Chair, Women in Litigation, Southern Methodist University School of Law Professional Seminar	1994
Member, Planning Committee, State Bar of Texas Advanced Evidence and Discovery Course	1990

PROFESSIONAL ADDRESSES AND PRESENTATIONS

"Ethics of Witness Preparation", to Texas Defense Lawyers' Association and to the Travis County Bar Association	2000
"Ethics for Government Counsel", to National Association of Attorneys General	2000
"The Aetna-Texas Settlement of Managed Care Litigation", University of Texas School of Law	2000
"Ethics for Government Lawyers" to the United States Attorney's Office for Northern District of Texas	1999
"Leadership in a Democracy: What It Takes Morally" given at the Provost's Academic Symposium at Southern Methodist University	1997
"What Makes a Leader", given to Dallas Young Lawyer's Association	1997

"Ethics of Lawyering" given to J. Reuben Clark Law Society	1997
"Ethics in the Electronic Era", given to the Plano Bar Association and the Dallas Women's Bar Association	1997
"The Law and Women", The Godbey Lecture Series, Southern Methodist University	1995
"Equality vs. Special Treatment: Different Dialogues in the Woman's Movement", given to the Southern Methodist University's Woman's Study Forum	1993
"The Imprisonment of America" given to the Southern Methodist University Breakfast Forum	1993
"Sexual Harassment in the Workplace" given at the ABA's Winter Meeting	1992
"Prosecutors' Ethical Duties" given to the Dallas County Prosecutors Association	1992
"Attorney-Client Privilege", given at State Bar of Texas Advanced Evidence and Discovery Course	1990
"Ethical Issues for Federal Prosecutors" given to Department of Justice, Tax Division	1990
"Professional Responsibility Issues for Corporate Counsel", given to Electronic Data Systems	1990
"Attorney-Client Privilege, Work Product Doctrine and Factors in Settling a Case", given to Centex Corp.	1989
"Persuasive Opening Statements", given to law firm of Winstead, Sechrest & Minick	1989
"Balancing Loyalty to the Client and Responsibility to the Judicial System", given to Federal Bar Association Seminar on Federal Practice	1989
"Different Approaches to Hearsay Evidence— State and Federal Comparison", given at Southern Methodist University Seminar on Emerging Trends in Texas Evidence	1989

"Ethical Considerations in Gathering and Using Evidence", given at Southern Methodist University Seminar on Modern Trends in Business Torts	1988
"Ethical Issues in Discovery", given at University of Houston's Seminar on Advanced Civil Discovery	1988
"Legal Ethics in Litigation", given to Dallas Bar Association	1987
"Ethical Considerations for the Guardian Ad Litem in Neglect and Termination Cases", given to Dallas District Court Seminar for Guardian Ad Litem	1987, 1989
"Confidentiality and Conflict of Interest Issues", given to Dallas Women Lawyers' Association	1987

LAW SCHOOL

University of Texas
Austin, Texas
J.D. with Honors, 1975

GRADUATE EDUCATION

University of Miami
Coral Gables, Florida
NASA Fellowship in International Studies, 1971-1972

UNDERGRADUATE EDUCATION

The American University
Washington, D.C.
B.A. in International Studies with Honors, 1971

24

INTER-COMPANY MEMO



Allender
Botterweck
Elmore
Lamp
Marhaver
McCaleb
McCann
Rusch
Rood
Stecklein
Taber
Wadsworth
FYI
Bill Caffey

Date: April 11, 1996

To: R. Balhorn D. Koch L. Purtell cc: B. Caffey ✓
J. Dumlér J. Moeller B. Spence W. Hanna
R. Fink C. Nelson J. Van Gelder C. Marhaver
B. Hall C. Nobles K. Vann L. Markel
J. Imbler S. Odell D. Watson
D. Kidd J. Pittenger R. Witte

From: C. Koch

After our SG&A meeting on April 4, Carl Marhaver observed that the increase in our costs was at least as big a contributor to our decline in return as was an insufficient increase in value added (sales minus raw material costs).

The attached table confirms Carl's insight. Over the last five years, while value added increased \$1,400mm, costs increased \$1,440mm (\$1,000mm operating, \$240mm depreciation, and \$200mm SG&A). In 1995, our total costs, other than income taxes, were \$5,500mm. If we were able to reduce this amount by just 10% through the elimination of waste (I'm sure there is much more waste than that), pretax earnings would increase \$550mm/yr.

To capture this opportunity, the leaders of the Operational Excellence Capability - Caffey, Marhaver, and Markel - will lead a campaign to change our processes that give rise to this magnitude of waste. Likely targets are: inadequate employee expectations leading to poor selection and low retention standards; poor decision making processes, including wrong people making decisions, poor economic thinking (especially the failure to connect costs with the creation of value), and lack of tough-mindedness; bureaucratization of the Internal Market System; poor procurement processes and decisions; poor project management; wasteful meetings and other communication methods.

To avoid the inertia, complexity, and bureaucracy problems associated with grandiose undertakings, Bill, Carl, and Lynn will prioritize and break this effort into bite sized pieces, led individually by them or others according to comparative advantage.

They will need your help and leadership in creating the new visions and taking on the risks of experimentation required for this effort to succeed. Please be prepared to take action on their initiatives as requested.

Thank you.



JE 000719

PS-

KII

<u>MM\$</u>	<u>Value Added*</u>	<u>Oper Costs</u>	<u>Dep</u>	<u>SG&A</u>	<u>BT Profits</u>
1990	4,900	3,500	260	250	900
1991	4,900	3,400	260	280	960
1992	4,700	3,500	350	320	540
1993	5,100	3,500	420	360	790
1994	5,700	4,000	420	390	820
1995	6,300	4,500	500	450	760
5 yr Δ	1,400	1,000	240	200	(140)

*Revenues less purchased crude oil and products

JE 000720

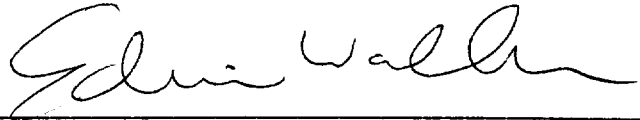
TRIAL COURT CAUSE NO. 51458

DANNY SMALLEY, INDIVIDUALLY)	IN THE DISTRICT COURT
AND AS INDEPENDENT)	
ADMINISTRATOR OF DANIELLE)	
DAWN SMALLEY, DECEASED)	
VS.)	KAUFMAN COUNTY, TEXAS
KOCH INDUSTRIES, INC., KOCH)	
PIPELINE COMPANY, L.P.,)	
KOCH HYDROCARBON COMPANY,)	
KPL/GP, INC., AND RONALD)	
GANT)	86TH JUDICIAL DISTRICT

I, Edwin Walker, Deputy Official Court Reporter in and for the 86th Judicial District Court of Kaufman County, State of Texas, do hereby certify that the following exhibits constitute true and complete duplicates of the original exhibits, excluding physical evidence, offered into evidence during the trial in the above-entitled and numbered cause as set out herein before the Honorable Glen M. Ashworth, Judge of the 86th Judicial District Court of Kaufman County, Texas, and a jury trial, beginning October 5, 1999.

(Nothing omitted.)

WITNESS MY OFFICIAL HAND this the 15 day
of November, 1999.



EDWIN WALKER, Texas CSR 5553
Expiration Date: 12-31-99
Deputy Official Court Reporter,
86th District Court
Kaufman County, Texas
P. O. Box 1361
Greenville, Texas 75403-1361
Phone: 903/450-4343 (Metro)
Fax: 903/450-4488

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ROLES AND RESPONSIBILITIES

DON CARSON
REVIEWED 08-30-95
REVISED 08-30-95

AREAS OF RESPONSIBILITIES:

Sterling #2 pipeline from the Red River south to the suction of Grapeland booster
Sterling #1 pipeline from the Red River south to Teague Booster.
Chico Lateral from the Chico plant to the Farmersville tie in
Lateral that runs from Corsicana booster to the Mobil pipe yard.
Trident Chico
Mitchell Bridgeport plant and tie in
Krum Booster
Farmersville Junction
Nevada Booster
Quinlan Booster
Corsicana Booster

ROLE:

Operation technician for the Quinlan area

RESPONSIBILITY:

- Pipeline maintenance.

EXPECTATION:

- Pig Sterling 1 & 2 on a regular basis as scheduled causing no delays turning in the proper documentation within 1 week.
- Perform line locates within 48 hr. and accurately..
- Respond to aerial reports within 48 hr.
- Provide accurate documentation for line locates and aerials reports to the appropriate people by the 20th of each month.
- Keep all of the sites in my area presentable and orderly including roads, ROW, signs, and vegetation.
- Have a good working knowledge of the pipelines and junctions in my district and all of their functions
- Assist any of the support groups who work in my district in any way possible
- Repairs made by me do not require to be fixed again.
- Washouts reported to Charles Misak and repaired as directed.
- Non DOT valves serviced bi annually.
- Maintain accurate documentation on projects to help better control costs

RESPONSIBILITY:

- Sterling 1 & 2 reliability and through put

EXPECTATION:

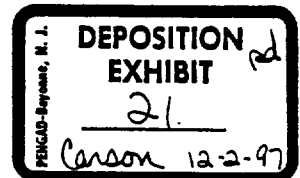
- Pumps, valves and motors at stations are available for service as needed
- Regular checks are performed on oil levels, filters, and other items that preventive maintenance could prevent a shut down
- Gain more knowledge on other aspect of the station so I can assist in trouble shooting
- Station is kept neat and presentable at all times
- Provide a safe working environment at the stations for myself and others
- Items of need are not found to be left unattended to.
- Have emergency numbers along with driving directions by 09-15

RESPONSIBILITY:

- Regulatory and safety compliance.

EXPECTATION:

- Rectifiers read by the end of every odd month.
- Valve DOT performed by the end of March and September.
- Monthly fire extinguishers checks.



DC 000351

- Documentation for inspections is filled out and turned in to regulations and Charles Misak.
- 4 in 1 forms are filled out complete for one-calls, aerals and maintenance revisions and turned in to Murry York and Charles Misak. With all appropriate information being documented, (PS reading, external pipe condition, stationing, coating condition)
- Attend public awareness meetings in my area
- Keep the general public informed about our system and fill out contact reports and turn into Murry York.
- Accurately mark our pipelines for excavation to insure no damage
- Know, understand and apply DOT part 195
- Provide a safe environment in my district for fellow employees and the general public
- Utilize the safety training and knowledge I have received.
- Be prepared to be a first responder to any emergency with all PPE required.
- Practice good environmental control methods
- No delinquent reports on tickler system
- Participate in tailgate safety meetings.
- Report near misses and safety concerns the Charles M. within 24 hr.
- No missing ROW signs
- Road crossings clean and visible.
- ROW maintained and kept down for aerial patrol.
- All necessary forms for activities are filled out and turned into Charles Misak within 1 week (Escavation, Hot Work, Orientation etc.,)
- If ever audited on the Sterling 1 revisions all of the necessary documentation has been completed and is order.

RESPONSIBILITY:

- Optimization

EXPECTATION:

- Review daily activities for optimum usage.
- Discover ideas to lower operating cost
- Identify and eliminate waste (Is there a better way)
- Manage overtime to a 10 hr per week average

RESPONSIBILITY:

- KII Employee

EXPECTATION:

- Have an attitude as on owner
- Understand the MBM system and be bought into the system.
- Utilize KII Mission, Philosophy and Principles in daily activities.
- Identify opportunities to increase my NPV to KII.
- Safety a number 1 priority
- Complete the year injury free
- Complete required training matrix.

RESPONSIBILITY:

- S-1 change outs

EXPECTATION:

- Daily evaluation of the utilization of manpower is considered
- Complete the change outs by Sept. 10
- No injuries occur during project
- Documentation is complete and orderly and turned into Medford be the end of Sept.

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

**APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS**

VOLUME 2 OF 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS

VOLUME 2 OF 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

APPENDIX

VOLUME 2

TAB NO.

26. Affidavit of Edward R. Ziegler, P.E., C.S.P. and Exhibits A-I thereto, including the Emergency Program: Hazardous Liquid and Natural Gas Pipeline Integrity Reliability Improvement for Koch Pipeline Company attached as Exhibit B
27. Plaintiff's Trial Exhibit No. 31 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
28. Trial Testimony of James Craddock from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
29. Trial Testimony of Edward R. Ziegler, P.E., C.S.P. from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
30. Plaintiff's Trial Exhibit No. 43 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas

TAB NO.

31. Trial Testimony of Charles Powell, P.E., from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
32. Trial Testimony of James Tucker from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
33. Trial Testimony of Don Carson from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
34. Trial Testimony of David Kilian from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
35. Plaintiff's Trial Exhibit No. 27 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
36. Plaintiff's Trial Exhibit No. 38 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
37. Trial Testimony of Charles Misak from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
38. Trial Testimony of Roger Floyd from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
39. Deposition and Trial Testimony of Bill Caffey from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas
40. Defendants' Trial Exhibit No. 10 from *Smalley v. Koch Industries, Inc., et al.*, Cause No. 51458, 86th Judicial District Court of Kaufman County, Texas

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IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, ET AL	(
)	CIVIL ACTION
	(
V.)	9:01 CV 132
	(
KOCH INDUSTRIES, INC.,)	JURY
ET AL	(

AFFIDAVIT

THE STATE OF TEXAS	(
)
COUNTY OF HARRIS	(

BEFORE ME, the undersigned notary, on this day appeared EDWARD R. ZIEGLER, P.E., C.S.P., who is personally known to me, and first being duly sworn according to law, upon his oath depose and said:

"My name is EDWARD R. ZIEGLER. I am over 18 years of age and my office is located at 5065 Westheimer Road, Suite 810, Houston, Harris County, Texas 77056. I am fully competent and qualified to make this affidavit. I have personal knowledge of the facts stated herein, and they are all true and correct to the best of my knowledge and understanding.

"I am a registered Professional Engineer (Petroleum Engineering - Texas) and a Certified Safety Professional (C.S.P.). I am an OSHA 500 Instructor and am or have been a member of several industry safety committees, including that of the

Society of Petroleum Engineers Gulf Coast Safety Committee, and of the Houston Association of Builders and Contractors. I also have a law degree, and am a member of the Texas State Bar in non-participating status.

"I have over twenty-eight years of experience in the engineering, oil and gas, safety, and pipeline industries. I have experience with the design, installation, construction, testing, inspection, operation and maintenance of natural gas, hydrocarbon, and hazardous liquid pipelines of various types. I am currently employed, as part of my Petroleum and Safety consulting practice, as the Consulting Oil and Gas Official for The City of Mont Belvieu, Texas. My duties in that position involve the City of Mont Belvieu, City Ordinances, Chapter 10 "New Industrial Activity", Pipeline, and other Oil and Gas Permits for activity in and near the City. A large part of my responsibility on those projects deals with pipeline safety and other related engineering and regulatory matters.

"I am familiar with and regularly use and apply the state and Federal regulations applicable to the subject pipeline systems as established by the United States Department of Transportation ("DOT") and the Office of Pipeline Safety ("OPS"), by the Railroad Commission of Texas ("TRRC"), and by and for other states and jurisdictions. I am also familiar with and regularly use and apply industry standards and practices applicable to the pipeline systems defined in documents surrounding this lawsuit.

“I will refer to the involved pipelines and related systems and facilities here as the “Subject Pipelines”, being all of the Koch Pipeline Company owned, operated, or partially owned or operated by Koch Pipeline Company, affiliates, subsidiaries, or other similar and related entities pipeline system, other than crude oil pipelines. Those entities will all be referred to here as “Koch Pipeline Company”; or simply as the “Koch entities”.

“I am familiar with the facts of and the issues stated in the pleadings and other documents surrounding this case, and have a thorough working knowledge of the technical aspects of this case, of the applicable federal pipeline regulations, of applicable state regulations, and of the relevant technologies and methodologies for uses and applications involving pipelines and pipeline safety, design, operations, maintenance, and training.

“My resume is attached as Exhibit A, which is incorporated in this Affidavit for all purposes (as are all exhibits enumerated in this Affidavit). All of the materials that I have reviewed, all applicable regulations and standards, and my library safety and pipeline materials are incorporated herein, including those listed in and referred to in the document that I authored, which is titled “EMERGENCY PROGRAM: HAZARDOUS LIQUID AND NATURAL GAS PIPELINE INTEGRITY AND RELIABILITY IMPROVEMENT FOR KOCH PIPELINE COMPANY”, dated August, 2001, and attached as Exhibit B.

“Based on my education, training, research, knowledge, and experience I have formed opinions as to the current safety of and the regulatory compliance

by and of the Koch entities as regards the operations and maintenance of the Subject Pipelines, and as to steps required on an emergency basis to immediately improve the safety, reliability, and integrity of the system. Additionally, I have reviewed information on the Koch entities' systems and specifically as to the Subject Pipelines, as to crude oil pipelines, and related facilities, operations, and systems as regards public information and reporting, regulatory compliance and filings, Consent Decrees entered/agreed to in Federal and state actions or initiatives, documents and reports related to those Consent Decrees, and other pipeline safety materials, including the body of material analyzed by Rimkus in the Texas/EPA case, by myself and others in the 'Smalley'/Kaufman County, Texas case, and others factual and documented information on incidents and spills on the Koch and Subject Pipeline systems. I have visited the P. D. Hamilton property in Trinity County, Texas and have inspected right-of-ways, observed pipeline markers, and measured the Koch pipeline depth and location of the Koch entities' interstate Sterling Two pipeline and a second, adjacent pipeline, believed to be the Koch intrastate Midstream pipeline, as they cross the subject P. D. Hamilton property.

"I have formed several opinions based on the information provided to me, obtained by me, and authored by me to date, and as it specifically applies to Defendant(s) in this case; and which opinions result in my engineering and safety conclusion that Koch Pipeline Company and the Koch entities must comply with

an Emergency Program as set forth here to operate and maintain a safe and reliable pipeline system with reasonable integrity:

- a. The Defendant(s) historically violated numerous Federal and State pipeline safety regulations and industry standards as set forth in the documents in this lawsuit and in other lawsuits and regulatory matters of which I am familiar.
- b. The Defendant(s) continue to violate numerous Federal and State pipeline safety regulations and industry standards as set forth in the documents in this lawsuit and in other lawsuits and regulatory matters of which I am familiar.
- c. Based on my examination of the Koch system and of the Subject Pipelines, their filings, and technical information, it is my opinion that the system is currently not in compliance with the applicable regulations and standards, is operating below the industry standard, and presents an imminent and looming danger and hazard to the Plaintiffs here, to the public, and to other stakeholders.
- d. The applicable Federal regulations and standards contain provisions in both the natural gas and hazardous liquid sections that relate to "safety-related conditions". A "safety-related condition" requires correction of safety problems or even shutting down the operation of a pipeline or pipeline segment when it is not safe. Such conditions as the cover depth at which a pipeline is buried is an operating and maintenance issue that may constitute an unsafe condition even if the

pipeline is grandfathered as to burial depth based on the date of construction, or if conditions have changed (i.e., increased population density, additional opportunities for construction contracts). See for example attached Exhibits C, D, and E.

- e. The Koch interstate pipeline crossing the P. D. Hamilton property was confirmed by me, based on data from the use of typical industry pipeline depth and cover measuring electronic equipment, and then field correlation of that equipment, as being covered or buried at less than the current required burial depth for new construction; and based on circumstances and land uses and potential land uses at that location, is in my opinion that this shallow cover depth constitutes a "safety-related condition" that adversely affects the safe operation of the pipeline and makes the pipeline unsafe. One important factor is that measurement of the depth of cover on the adjacent Koch intrastate Midstream pipeline, which is also across the P. D. Hamilton property and is parallel to the Koch interstate Sterling Two pipeline, was found to be at depths as shallow as eight (8) inches below the surface of the ground. The rupture of the intrastate pipeline could from an engineering perspective (and with known historic examples) affect the safety and integrity of the interstate pipeline; as adjacent pipeline ruptures or damage historically have resulted in the failure of adjacent pipelines. The current Federal regulations and industry standards and practice (American Society of Mechanical Engineers/American National Standard (ASME/ANSI) B31.4 (liquids) and B31.8 (natural gas)) require a minimum cover or depth of burial in the area of thirty (30) inches (depending on class, location, land use, and other

circumstances); again the P. D. Hamilton property has cover less than twenty-four inches for the interstate hazardous pipeline and as shallow as eight inches for the intrastate natural gas pipeline, respectively.

- f. Other conditions on and of the Subject Pipelines, such as the location of and lack of pipeline markers on the P. D. Hamilton property, which are not “over” or “on” the pipeline or are not present for each pipeline or to indicate each pipeline that is present, or are an unsafe and unreasonable distance from the pipeline which make the pipeline location uncertain and not reasonably discernable to persons or workers in the area, are additional factors that make the pipelines unsafe and do not meet a reasonable and necessary industry standard and constitute additional “safety-related conditions”. See for example American Petroleum Institute (API) Standard 1109, “Marking Liquid Petroleum Pipeline Facilities (1993)”, attached in part as Exhibit F.
- g. It was and is foreseeable to Defendant(s) that the failure to comply with the applicable regulations and to reasonably meet the necessary industry standard required for safe operations has, would, and/or will lead to external corrosion, loss of integrity, third-party encroachment, contact, and damage, or other defects or unsafe conditions and lead to failure of parts of the Subject Pipelines.
- h. It was and is foreseeable to Defendant(s) that the failure to comply with the applicable regulations and to reasonably meet the necessary industry standard required for safe operations has, would, and/or will lead to personal injury, potential fatalities, and large amounts of

property damage of and to persons who are grantors of pipeline right-of-ways and other affected persons, public interests, and stakeholders.

- i. It was and is foreseeable to Defendant(s) that the failure to comply with those regulations set forth by the U.S. DOT/Office of Pipeline Safety found at 49 CFR Part 191 through 49 CFR Part 199, and in the Hazardous Liquids Pipeline Safety Act of 1979 at 49 USC 2001 et seq., the Pipeline Safety Law at 49 USC 60101 et seq., and various regulations that are similar to these standards in principle and intent, will or would proximately cause leaks and failures such as and would cause incidents, personal injury or death, or other serious personal, property or environmental damage.
- j. The failures of Defendant(s) have lead to specific identifiable events such as (1) an incident in August, 1996, where a Koch Pipeline Company interstate hazardous liquid pipeline burst in Kaufman County, Texas, (the Sterling One system) due to known corrosion problems and history of the pipeline, and due to management, operating, and maintenance failures (Resulted in two deaths and property damage), (2) an incident in November, 1994, where an Angelina County, Texas-owned road maintainer or grader struck a 24-inch diameter Koch interstate natural gas pipeline that was covered by only several inches of dirt and gravel on an unpaved country road traveled by a local school bus (Resulted in one injury, counter-suit by Koch against Angelina County, Texas, for value of lost natural gas from line after rupture), (3) a series of events and incidents occurring over several years which resulted in leaks and spills of crude oil, and

the release of toxic, noxious, and dangerous and hazardous chemicals, and resulting in damages involving Koch plants, refineries, and related facilities (Resulted in environmental and property damage; two Consent Decrees entered/agreed by Koch), and (4) hundreds of other reported, under-reported, and unreported leaks, incidents, and releases that have occurred in the last ten years throughout several states which the Koch system traverses, that resulted in injuries and property damage, and numerous near-misses. See attached Exhibit G.

- k. The cited Federal pipeline safety regulations are minimum standards; actual operational and field experience and the surroundings, land use, and similar factors and circumstances must dictate the correct method and means of compliance in the factual situation and circumstances actually presented to the prudent operator. The failure to meet or exceed the applicable Federal pipeline safety regulations to reach a reasonable industry standard and practices necessary for safe operations and maintenance of the Subject Pipelines was and is foreseeable to Defendant(s) as leading to historical failures, present concerns, and future and imminent failures on the Subject Pipelines and other parts of the Koch entities' system.
- l. Federal pipeline safety regulations address many types of issues, each of which, if violated, are known to lead to and have constituted the proximate cause of a pipeline failure and resulting injuries, death, or property damage. Of concern here, and based on my review of information to date, it is my opinion that Defendant(s) currently violate and violated Federal pipeline safety regulations as follows:

1. Safety-related conditions (49 CFR 191.23, 192.14, 192.601 et seq., and 195.400 et seq.).
 2. Public awareness or public education (49 CFR 192.616 and 195.440).
 3. Pipeline repairs and maintenance (49 CFR 192.701 et seq., and 195.422).
 4. Develop and implement proper employee training (49 CFR 192.13 and 195.403).
 5. Inspect and maintain right-of-ways (49 CFR 192.613, 192.705 and 195.412).
 6. Corrosion control and corrosion monitoring (49 CFR 192.451 et seq., 195.414, 195.416, and 195.418).
 7. Pipeline markers (49 CFR 192.707 and 195.410).
 8. Failure to provide and maintain adequate cover (49 CFR 192.327 and 195.248).
 9. Failure to follow ASME/ANSI B31.4 and B31.8; as adopted by DOT/OPS and others.
 10. Failure to maintain maps and records (49 CFR 192.617, 192.709, 195.286, and 195.404).
 11. Failures during return to service, uprating, and conversion of service (49 CFR 192.14, 192.551 et seq., and 195.5).
- m. Defendant(s) failed to follow American Petroleum Institute (API) standards, National Association of Corrosion Engineers (NACE) standards, and Koch's own standards and practices. These failures include, in brief and summary form:

1. Failure to properly deal with safety-related conditions (ASME/ANSI B31.4 and B31.8).
 2. Failure to maintain proper and adequate cover over pipelines (ASME/ANSI B31.4 and B31.8)
 3. Failures of repair and maintenance (API 2200).
 4. Failures to provide adequate cathodic protection (NACE RP-01-69).
 5. Failure to provide adequate cathodic protection (KTOS STD 1301.076, KOG STD 1302.076).
 6. Failures to follow Koch Operations and Maintenance Manual (O&M) (ASME/ANSI B31.4 and B31.8).
 7. Training of operators, public information, and emergency preparedness (API 1100 Series).
 8. Failure to adequately mark pipelines (see for example API 1109).
- n. It is foreseeable to Defendant(s) that violation of applicable regulations and failure to meet the necessary industry standard did, would, and will, within engineering and safety management probability, lead to and proximately cause the subject historical incidents and similar future incidents, respectively, involving the Subject Pipelines and other parts of the Koch entities' system.
- o. In engineering practice, in the safety field, and under the Federal pipeline and similar pipeline safety regulations and standards applicable to the Subject Pipelines, many factors other than pipe corrosion rates and the encroachment of third-parties must be

considered by the prudent pipeline operator and are known and foreseeable factors in the industry as being causal, whether alone or in some combination with other factors, of a pipeline failure.

- p. It is foreseeable to the prudent pipeline operator, and was foreseeable to Defendant(s) here, that all of the factors which adversely affect the condition, safety, reliability, and integrity of a pipeline may cause a failure or may indicate trends or problem areas that may be present in and of themselves or combine with other factors to create the predictable and certain failure of the pipeline system.
- q. As an analogy, automobile tires are subject to Federal regulations and are marketed with a "tread wear" rating, indicating miles of predicted usefulness (and, based on the rating factors and methods, predicted safety). If tread wear (analogous in a pipeline safety context to such factors as pipe corrosion rates) was the only factor to consider, then automobile tires would never fail before the rated miles had been driven. It is known in our common experience that many factors other than mileage affect the life and safety of an automobile tire, so thus there are numerous factors in the design, operation, and maintenance of the Subject Pipelines that require management, engineering, and safety input other than attempting to simply follow the "skeleton" or "minimum" Federal regulations. Individual circumstances, activity, changes in land use, and other factors must be considered for each pipeline.

- r. The industry, through such organizations as the American Petroleum Institute, and regulators, through the Office of Pipeline Safety (United States Department of Transportation – Research and Special Projects Administration (RSPA) determined at least by 1995 that the minimum Federal regulation-format was not sufficient for determining the condition of the pipeline systems in the United States and for monitoring their safety and safe operation and maintenance. Such documents as the 1995 Joint Risk Assessment Report (OPS/API – See Exhibit H) directed that risk assessment and evaluation of the various pipeline systems were the necessary industry standard and recommended as an industry practice.

- s. Koch and the Defendant(s) here, by utilizing such methodology as “Market-based Management”, which technique, and especially as implemented and applied by Koch and the Defendant(s) here, emphasizes financial and cost considerations as a driving force, including employee training, in operating based on cost and pay-back or return of expense or investment rather than prudent operations, safe pipeline operations, or even compliance with safety regulations. The spirit and letter of the Federal regulations requires that pipeline operators implement profit/expense considerations and controls in conjunction with prudent, required, and necessary maintenance, repair, inspection, and monitoring of pipelines. In this regard, Koch and the Defendant(s) are performing well below the stated industry standard in such areas as risk management and assessment of the pipeline systems. The Koch “Market-based Management” policy and system sets forth policies at all management and supervisory levels in the Koch system

that encourages and requires employees to base decisions on cost and pay-back versus such factors as pipeline safety, regulatory fines, leaks and incidents, and contrary to those policies required by the letter and spirit of the Federal pipeline safety regulations. Specifically, Koch on a system-wide basis has violated such provisions of the Federal regulations as the safety-related conditions and training provisions. These regulations, as enumerated also in paragraphs above, are found in such specific regulations as those for natural gas pipelines at 49 CFR 192.603, 192.605, 192.701, and 192.703; and for hazardous liquid pipelines at 49 CFR 195.401, 195.402, and 195.403; which are listed here as examples rather than to exhaustion.

- t. The “risk assessment and evaluation” formats as recommended by the OPS and API, and a new API standard, “Risk Assessment and Integrity Programs for Liquid Pipelines” (API RP 1129, 1996 – See Exhibit I), address the necessary practices, procedures, assessments, and such factors as technology and methodology upgrades necessary to safely operate such interstate pipeline systems in the United States.
- u. The Office of Pipeline Safety (“OPS”) has received public criticism and much attention for the failure to either require compliance or to advocate and implement enhanced regulations and policies to make the interstate pipeline system safe. OPS has allowed the interstate pipeline operators to be essentially self-policing; with the result that operators such as Koch and the Defendants here, especially when implementing “Market-based Management” and similar policies as Koch and the Defendant(s) apply those techniques, are effectively operating in an

environment ranging from poorly-self-regulated to essentially unregulated.

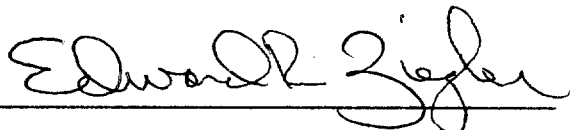
- v. The industry standard required now, both to meet the minimum requirements of the Federal pipeline regulations, and to meet and satisfy the current industry recommended practices and standards for risk management-based pipeline integrity and reliability, defines the “Necessary Industry Standard”.
- w. The “Necessary Industry Standard”, which is within the scope and range of currently accepted and implemented industry standards and practices, analyzes, selects, and applies the available technology and methodology that is in use and feasible in the United States pipeline industry today. This is the level of standard that is required to provide a safe and reliable pipeline with acceptable and achievable integrity based on the practices, equipment, technology, and methodology available and actually used on a cost-effective basis in the pipeline industry today.
- x. The document indicated earlier in this Affidavit as attached as Exhibit B, “EMERGENCY PROGRAM: HAZARDOUS LIQUID AND NATURAL GAS PIPELINE INTEGRITY AND RELIABILITY IMPROVEMENT FOR KOCH PIPELINE COMPANY”, dated August, 2001, sets forth the required steps, procedures, program development, training, and budget for Koch Industries and related entities, subsidiaries, ventures, and affiliates to determine, attain, and

maintain the "Necessary Industry Standard", which is synonymous for "a safe and reliable Subject Pipeline system".


- y. The failure of Koch Pipeline Company to follow the requirements set forth here as violations of the pipeline safety regulations and the necessary industry standards and practices will continue to expose grantors/landowners of or near the Koch Pipeline Company right-of-way and other affected persons, public interests, and stakeholders to the hazard of an unsafe and unreliable hazardous liquid and natural gas pipeline system; and to predictable and foreseeable instances of injury, death, and property damage.

"These opinions are subject to change if additional information is made available.

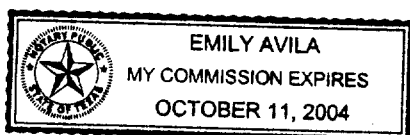
"FURTHER AFFIANT SAYS NOT."


EDWARD R. ZIEGLER, P.E., C.S.P.

SWORN TO AND SUBSCRIBED BEFORE ME on the 25th day of September, 2001.


Ms. Emily Avila
Notary Public, In and For The
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SEAL





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Juris Doctor (1979)
University of Pittsburgh (Two Years) / South Texas College of Law (Degree)

Other: 15 Credits M.S. level safety engineering.
Various oilfield, safety, construction, environmental and
economics schools/seminars, ISO 9000.

EXPERIENCE:

PETROLEUM AND SAFETY CONSULTING 1981 to Present
Oilfield, construction, and safety management. Safety audits, OSHA, operations, engineering, safety programs, design, industry standards and practices.

MAINTENANCE AND WELDING COMPANY 1987 to 1989
Oilfield, plant and maritime industries providing labor and services.

HOME PETROLEUM CORPORATION 1977 to 1981
Drilling and Production Manager. Management, operations, construction, pipeline, and safety responsibility. Geographic area U.S., offshore, and international. Well depth 600 feet to 21,000 feet. Much field work for problem solutions.

MARATHON OIL COMPANY 1972 to 1977
Various engineering responsibilities, including drilling, safety, production, reservoir, construction. Toolpusher on company-owned rigs. Drilling, construction and production onshore, offshore and international. All types of land and maritime rigs and vessels including barge rigs, jackups, drillships, semisubmersibles, and submersibles. High-angle, deep wells to 20,500 feet.

PROFESSIONAL:

Registered Professional Engineer - Texas (Since 1986)
Certified Safety Professional (Since 1990)
OSHA 500 Instructor (Since 1993)
Society of Petroleum Engineers - Gulf Coast Chapter Safety Committee
(1991-1993) (Charter Member)
Safety Committee, Associated Builders and Contractors (1992-1995)
Texas Workers' Compensation Commission Extrahazardous
Employer Approved Professional Source (1992-1996)
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EMERGENCY PROGRAM:

HAZARDOUS LIQUID AND NATURAL GAS PIPELINE

INTEGRITY AND RELIABILITY IMPROVEMENT

FOR

KOCH PIPELINE COMPANY

Necessary Industry Standard

Assessment

Planning and Documentation

Implementation

External Audit

Improvement

August, 2001 Version 1.1

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PREFACE

The purpose of this program is to specify the level of performance for the Subject Pipelines that has become the accepted industry standard for the assurance of pipeline integrity, reliability, and safety; and to require Koch Pipeline Company to quickly meet that level of industry standard, called here the "Necessary Industry Standard", and improve their overall safety and performance.

The current industry standard is as defined by such materials as the United States Department of Transportation "Safety Related Condition" criteria found at 49 CFR 195.400; which effectively removes such factors as "grandfathering" and "minimum standards" as concepts in the appropriate determination of hazards and risks for a given situation or circumstance; and the current industry standard is effectively stated in such materials as American Petroleum Institute ("API") Recommended Practice 1129, "Assurance of Hazardous Liquid Pipeline System Integrity". The principles set forth in API RP 1129 include "Integrity assurance practices should extend beyond these minimum required activities (the Federal/TexasRRC regulations in 49 CFR). Risk Assessment and Hydrostatic Testing (with operating pressure downrating considered for "vintage" systems) are also factors that are stated by the API RP 1129 principles to go beyond the Federal/TexasRRC regulations, which are "minimum regulations", but which are below the "minimum industry standard". While API RP 1129 is written for liquid pipelines, all of the principles therein are equally applicable to natural gas and other pipeline systems.

The requirements set forth here define a reasonable industry standard that takes into account (1) current API recommendations, (2) demonstrated levels of performance agreed to by Koch Pipeline Company in two recent Federal Court Consent Decrees, and (3) necessary requirements to raise Koch Pipeline Company to a reasonable level of safety and performance because of its demonstrated poor pipeline integrity, reliability, and safety performance.

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EXECUTIVE SUMMARY

Emergency Program for Pipeline Integrity and Reliability - What Koch Pipeline Company Must Do Because of the Continuous and Ongoing Hazard

Because the hazards addressed here for correction are continuous and ongoing, the Koch Pipeline Company organization must commit, on a rapid and urgent time frame ranging from six months to two years for implementation, and to five years for effectiveness checks, upgrading, and monitoring, to develop and execute programs for the Hazardous Liquid and Natural Gas Pipeline Integrity and Reliability Improvement Program (the "Program"). The elements of the Program, and the resources and tasks necessary to design, implement, and make the Program successful are illustrated in the enumerated sections below.

Koch Pipeline Company must determine the organization and number persons and other resources necessary to accomplish the goals, schedule, and to ultimately complete the Program. The Auditor will determine periodically whether the required resources are committed as determined by progress and adherence to the schedule; and whether the Program, goals, and commitments are ultimately achieved and honored.

A significant starting point for this program will be determination of the Necessary Industry Standard that will be applied for each element of the technical aspects of the Program.

Plans, Elements, and Technical Guidelines under this Program, while substantially complete, are in continuing development. Such items that may be enhanced and updated, include but are not limited to, the MOP/MDOP criteria, pipeline marker programs, assessment requirements, and the Auditor's enforcement mechanisms.

DEFINITIONS

See Table 1: Definitions in attached Appendix A for working definitions; with backup material included.

INTRODUCTION

Koch Pipeline Company is required to develop the Hazardous Liquid and Natural Gas Pipeline Integrity and Reliability Improvement Program (the "Program") because Koch entities have a demonstrated history, philosophy, and documented and well known failures in the areas of regulation, safety, industry practice, and its own practices and policies. The Program will set forth goals and requirements to improve the Subject Pipeline system so that it meets the apparent current industry standards and practices, regulations, and that sets performance goals for performance somewhere between acceptability at the level of the Necessary Industry Standard and excellence.

The Subject Pipeline systems covered by the Program, as further defined in the definition Appendix A, are active and inactive hazardous liquid and natural gas pipelines and connected and related facilities that cross, approach, or otherwise affect thousands of landowners and other private and public interests in the United States.

The Program must be implemented to improve Koch Pipeline Company's hazardous liquid and natural gas pipeline operations ("Subject Pipelines") and to meet and exceed the Operating and Maintenance ("O&M") Requirements of regulations and industry standards. The Program does this by:

1. Committing Koch Pipeline Company to operational and maintenance improvement.
2. Implementing processes, technologies, methodologies, and training that improve pipeline integrity and reliability.
3. Assuring that Koch Pipeline Company operates its pipeline in a manner that meets the definition here of Necessary Industry Practice.
4. Assuring Koch Pipeline Company operates its pipeline in a manner that uses such materials or resources as API, OPS, and ASME/ANSI standards where specified.

5. Implementing processes that are consistent, sustainable, and have a long-term positive impact on safety, integrity, reliability, and performance.
6. Providing specific technology and equipment for the benefit of landowners/right-of-way lessors, and other affected persons and stakeholders to improve pipeline safety and the safety of the community.

The Program requires six Plans or types of action to address the improvement and future safer and reasonable operation of the Subject Pipeline system. These Plans, in summary form, are:

1. Assess the current state of the Subject Pipeline system to determine its physical condition.
2. Repair, recondition, or replace the Subject Pipelines as appropriate and necessary according to the assessment.
3. Design and implement a system for warning affected, potentially affected, and other persons, responders, and stakeholders of leaks or other operating problems or anomalies on the Subject Pipeline system.
4. Implement and continue on an ongoing basis Necessary Industry Practice for pipeline operation that will maintain and upgrade the physical condition of the pipeline.
5. Implement ongoing use and adoption of Necessary Industry Practice for pipeline systems, materials, technology, methodology, and systems for operations and leak detection.
6. Develop and implement improved pipeline marking, locating, third-party/outside risk assessment, and identification of the Subject Pipeline system.

The activities and documentation in the Program that follow, when properly and timely accomplished, will satisfy each of these Plans. The Program outlines numerous plans to address hazardous liquid and natural gas pipeline integrity and reliability required here. These Plans generally cover the sections as set forth in the Table of Contents above.

Each of these plans states Commitments that are components of the scope and goal of the Program. The actual work processes or steps required to implement and execute tasks and elements that fulfill these Commitments are called "Activities" in

each Program section or Plan below. The following lists gives some initial resources required:

Functions and Disciplines

1. Management Commitment
2. Operations
3. Legal and Regulatory
4. Engineering
5. Safety
6. Training
7. Scheduling
8. Budgeting
9. Reporting

Policy Determinations

1. Policy – Commitment and “Necessary Industry Standard”
2. Policy - Risk Management
3. Policy - Safety
4. Policy - Regulatory
5. Policy - Implementation
6. Policy - Training

Tasks

1. Risk Analysis - Policy
2. Risk Analysis – Methodology
3. Risk Analysis – Perform
4. System Assessment – Current Policy and Procedures
5. System Assessment – Methodology Selected
6. System Assessment – Perform
7. System Upgrade and Components Selection
8. Planning
9. Documentation
10. Training
11. Implementation
12. Effectiveness Monitoring
13. Results Monitoring
14. Management of Change
15. Reporting
16. External Audit Function and Enforcement

Reporting Periods

Management, employees, and outside resources, with an appropriate budget, will accomplish determination of the Necessary Industry Standard, and:

1. The first reporting period (Year 0.0 to 0.5) - develop and demonstrate commitment, philosophy, and policy; begin developing and implementing training.
2. The first reporting period (Year 0.0 to 0.5) - determining and selecting technology and methods and begin to assess system condition.
3. The second reporting period (Year 0.5 to 1.0) – continuing assessment of system; developing Technical Guideline material to repair, recondition, and maintain the system, and beginning implementation.
4. The third reporting period (Year 1.0 to 2.0) - continue implementing Technical Guidelines and training.
5. The fourth reporting period (Year 2.0 to 3.0) - monitoring effectiveness and retooling the plans for effectiveness.
6. The fifth and sixth reporting periods (Year 3.0 to 4.0 and Year 4.0 to 5.0)- monitoring and fine tuning the plans and Program.

Koch Pipeline Company will prepare and deliver a Semi-Annual Report within 30-days of the end of each reporting period or part of a reporting period indicated above, with a report for each six calendar months.

EXTERNAL AUDITING OF OPERATING REQUIREMENTS

The third party auditor ("Auditor") will be selected to assemble a review team to determine whether Koch Pipeline Company:

1. Properly and realistically assesses and reports its current pipeline condition.
2. Has reasonably and properly assessed the Necessary Industry Standard and the regulatory environment.
3. Has reasonably and properly determined the initial risk assessment and risk assessment policies.

4. Has utilized proper methodologies to assess Necessary Industry Standard for its pipeline review, integrity determinations, monitoring, leak detection, and response/public information.
5. Has properly developed and implemented safety and operational procedures and policies.
6. Has properly developed and implemented training programs for management and employees; including segments for risk assessment, safety, operations, and maintenance philosophy and policies.

With the purpose and required goal of developing Technical Guidelines for improvement and upgrading of its hazardous liquid and natural gas pipeline system, procedures, and policies, Koch Pipeline Company shall initially determine and document its intended programs and policies; along with a schedule for planning, development, implementation, and follow-up monitoring; as well as a budget determination for the overall process as allocated to each Plan and time frame.

The Auditor shall then review the stated Plans and budget, and then actively and proactively participate in setting the appropriate performance standards, completion criteria, timetables and then to review and comment on the approved Technical Guidelines published. This process will assure that the programs, criteria, and processes Koch Pipeline Company plans and implements meet the Necessary Industry Standard defined here.

A full summary of Technical Guideline requirements for each part of the system, policies, operations, maintenance, and training is included in the following enumerated sections A through G, "Summary of Technical Guidelines Required for Hazardous Liquid and Natural Gas Pipeline Integrity and Reliability Improvement Program." (the "Program").

The Auditor will assemble an audit team to perform the audits required to determine if Koch is meeting Program obligations, commitments, and schedules.

The Auditor's process for the first semi-annual audit will not consist of a single point-in-time audit, but will extend over a period from the selection of the Auditor to submittal by Koch Pipeline Company of the first Semi-Annual Report at the end of the first reporting period. The Auditor will then prepare the first audit report in accordance with the required delivery dates. The first audit will assess:

1. Completion of activities as claimed in the first Koch Pipeline Company Semi-Annual Report (at Year 0.5).
2. Technical Guidelines actually developed as to quality and evidenced completion percentages and progress as of each reporting period.

In addition to the above-stated audit protocol for the Program, the Auditor will review and comment on the effectiveness of operating systems and processes outside of the audit protocol scope to the extent that they relate to upgrading and improving the integrity, reliability, and safety of the Koch Pipeline Company natural gas pipeline system; and rising to the level of the Necessary Industry Standard.

The Auditor will deliver reports within 30-days after each report delivered by Koch Pipeline Company; or if no report is delivered by Koch Pipeline Company or if the reports are not delivered on time, the Auditor will so report by at most 60-days after the end of each reporting period or six months, which ever is the lesser time.

The Auditor will have an enforcement mechanism to accomplish the Program.

SUMMARY OF TECHNICAL GUIDELINES FOR
HAZARDOUS LIQUID AND NATURAL GAS PIPELINE
INTEGRITY AND RELIABILITY IMPROVEMENT PROGRAM

COMPLETION CRITERIA AND ASSESSMENT

The following sections provide the Commitment and Required Activities for each Plan and Element. As the project progresses, these sections will serve as an outline for claiming or determining the status of each Plan and an update of Activities and preparation of or progress on work, documents, or other materials since the last reporting period for each of the Plans in the Pipeline Integrity and Reliability Improvement Program.

Each of these Plans consist of one or more Plan Elements. Each of the Plans or segment of the Program has one or more elements.

Each of the Plan Elements has the structure for requirements or for Technical Guidelines as described below:

Scope: Defines what the Plan or Plan Element covers.

Plan Element Commitments: States commitments that Koch Pipeline Company has made regarding the particular Plan Element. These commitments will guide operations to meet or exceed what is determined to be Necessary Industry Standard for an overall pipeline integrity and reliability program.

Activities Required: Enumerated listing of Activities required to plan, develop, and implement the Plan or its element(s).

As the Program progresses, at each reporting or audit period, Koch Pipeline Company and the Auditor will evaluate the progress claimed, demonstrated, and/or determined and a "Earned Completion" value as a percentage of full compliance will be assessed by both Koch Pipeline Company and the Auditor; as based on the evaluation by each. For each Plan and Activity, the Earned Completion percentage will be estimated using the following guidelines. These guidelines are applied to Technical Guidelines and all other Plan or Program segments or elements:

Table 2: Earned Completion Guidelines

<u>Earned Completion</u> (%)	<u>Level of Activity Completion</u> (Terminology / Progress)
5%	Scope defined and definition of "Necessary Industry Standard"
20%	Protocol or definition of document developed and approved
40%	First draft document
50%	Final draft for Koch and Auditor or other review

60%	Final approved and issued by/for Koch and Auditor
80%	Implementation
100%	Effectiveness determined and/or revised and re-implemented

The above percentages are to reflect goals reached and are not to merely reflect effort, money, or time spent. Each goal must be met within the specified reporting periods above. Any reporting period completion results of less than 100% for items specified to be completed during a reporting period or during previous reporting periods are failures on the part of Koch Pipeline Company to implement and are violations of the plan and required progress.

The Plan elements and Activities Required sections given for each Technical Guideline below list minimum requirements; the logic or progression of the work or protocol may require additional steps or listings.

A: TECHNICAL GUIDELINES AND OTHER PLANS

1.00 Initial Assessment Plan

Scope

This Plan establishes the methodology, criteria, goal, and schedule to assess or validate the current condition of the Subject Pipelines as required by the goal and objective of the Program.

Plan Element Commitments

1. The Key Commitment is to, "Assess the condition of the Subject Pipelines and restore or recondition, if necessary, to physical condition that is accepted as Necessary Industry Standard or better."
2. On a pipeline-by-pipeline basis, determine the appropriate inspection, internal line testing, hydrostatic testing, or other technology or methodologies for determining the condition, reliability, and integrity of the section or line.
3. Based on the determination in 2. above, conduct an integrity evaluation of the Subject Pipelines.
4. Pressure test any of the Subject Pipelines that have not been pressure tested for five years, any pipeline that has had a leak of any type and from any cause within the last five years, and hydrostatically test any pipeline that is operating above 20 % of its SMYS.
5. Conduct close-interval and depth-of-cover surveys on the Subject Pipelines, an exposed pipe identification survey and evaluation, and detailed and accurate mapping of the Subject Pipelines. (See CIS and other plans below).
6. Conduct a pipeline marker survey of the Subject Pipelines and place, replace, or repair signs, as appropriate and necessary. (See Marker Plan below).

Activities Required

- 1.00.01 Identify lines that have not been smart pigged or hydrostatically pressure tested since January 1, 1997.
- 1.00.02 Identify lines with inadequate pressure test documentation and identify lines to be re-tested based on lack of documentation.
- 1.00.03 Complete smart pigging or pressure testing of these lines.
- 1.00.04 Develop criteria for the repair or removal of verified corrosion or other defects that affect MOP.
- 1.00.05 Complete repairs, reconditioning or replacement in accordance with adopted current industry standards, risk assessment, and determined criteria.
- 1.00.06 Define the pressure test and internal line evaluation or other selected evaluation review process and documentation requirements.
- 1.00.07 Define requirements of leak history and corrosion rate review and documentation.
- 1.00.08 Complete and document review of pressure test and internal line evaluation data.
- 1.00.09 Complete and document review of leak history and corrosion rate.
- 1.00.10 Determine and document exposed pipeline listing requirements.
- 1.00.11 Establish and document exposed pipeline evaluation procedure.
- 1.00.12 Conduct close-interval depth-of-cover and exposed pipe identification surveys and document cover of all Subject Pipelines and exposed pipe locations.
- 1.00.13 Complete remedial action, if necessary, including covering and lowering.
- 1.00.14 Survey and document marker placement.
- 1.00.15 Develop a pipeline marker condition criteria.

1.00.16 Conduct and document pipeline marker surveys and corrective actions in accordance with the condition criteria.

1.00.17 Use the marker survey, condition, and corrective actions taken to implement the marker requirements of API 1109 and the Marker Plan here.

1.01 Risk Assessment Plan

Scope

This Plan will improve Koch Pipeline Company's integrity and reliability management practice of risk assessment using tools to establish a ranking of Subject Pipeline segments to guide integrity and reliability management.

Plan Element Commitments

1. The Key Commitment of the Risk Assessment Plan is to, "Sustain a system that will identify and prioritize maintenance and inspection activities based on assessment of the pipelines physical condition, operational factors, and external factors."
2. Formalize a risk assessment process, which will utilize a ranking index model as its primary decision support tool.
3. Review, revise, and expand, as needed, existing ranking index models to achieve appropriate sensitivity to input data and include all Subject Pipelines.
4. Enhance the integrity and reliability management decision-making process by integrating a risk assessment process with the Prevention, Maintenance, and Inspection Plan, and work processes.

Activities Required

1.01.01 Review current practices and methodologies with respect to using risk assessment modeling and risk management.

1.01.02 Establish and document risk assessment modeling philosophy and process; to include a combination of the Model, Knowledge, and Experience formats as set forth in 1995 report on such methodologies by API/OPS.¹

1.01.03 Define input elements.

1.01.04 Identify required models and tools for development and/or enhancement.

1.01.05 Prioritize model and tool development and/or enhancement.

1.01.06 Develop criteria and weighting of input variables and attributes.

1.01.07 Conduct sensitivity analysis and adjust weightings of variables and attributes as needed.

1.01.08 Gather and refine data to populate database, as required.

1.01.09 Conduct reality testing of models.

1.01.10 Document the rational of variables and attributes used in the models.

1.01.11 Finalize risk assessment modeling philosophy and process documents.

1.01.12 Establish process of evaluating activities which influence the index model ranking and develop corresponding documentation.

1.01.13 Establish maintenance and inspection activity prioritization process and corresponding documentation.

1.01.14 Document the activity evaluation and prioritization processes.

1.01.15 Integrate data collection and data maintenance into MOC and documentation practices.

1.01.16 Consider and develop, as appropriate, a system to measure the use and improved of the risk assessment process.

¹ API/OPS, "Risk Management Within The Liquid Pipeline Industry", Final Report, June 20, 1995, cover page attached in Appendix A for identification.

1.02 Prevention, Maintenance, and Inspection Plan

Scope

This Plan will establish practices, systems, and processes for prevention, maintenance, and inspection activities necessary to manage natural gas pipeline integrity and reliability. This Plan is divided into numerous Plan elements that address specific aspects of prevention, maintenance, and inspection.

Plan Element Commitments

1. The Key Commitment is to, “Manage for leak prevention by determining, applying, and documenting Necessary Industry Standard, or better, for maintenance, inspection, and operation activities.”

Activities Required

1.02.01 The activities under this Plan are set forth in other Plans and Technical Guidelines.

1.03 Maximum Operating Pressure (MOP) Management – Here to determine new criteria called the Maximum Determined Operating Pressure (MDOP)

Scope

This Plan Element will improve Koch Pipelines Company’s programs to provide systems and processes that consistently manage pipeline MOP. Plan 4.00, Pressure Monitoring and Recording Equipment, covers installation, operation, and maintenance practices associated with pressure equipment affecting MOP. The new operating pressure after implementation of the Program and Plans in this section will be call Maximum Determined Operating Pressure (“MDOP”).

Plan Element Commitments

1. The Key Commitment is "To determine which pipelines, due to age, materials, location, test/inspection results, or history (including corrosion, leaks, etc.) will be operated at a lower MOP (the MDOP) for safety and risk management considerations, or removed from service or replaced".
2. Develop a MOP listing for the Subject Pipelines. This list will include segment name, established MOP, the method of establishing MOP, and the date the existing MOP was established.
3. Formalize and gain consistency in the establishment of MDOP on newly constructed lines, newly acquired lines, and inactive lines to be placed into service.
4. Determine the MDOP for each segment or part of the Subject Pipelines.
5. Conduct an assessment to ensure pressure control/limiting devices are at the appropriate settings so that normal operation is within the MDOP and surge pressures or other conditions varying from normal operations are within MDOP or at a lower pressure depending to the condition and history of the line.

Activities Required

- 1.03.01 Define and document MOP listing data search criteria and quality expectations.
- 1.03.02 Collect data for MOP listing per search criteria and quality expectations.
- 1.03.03 Compile MOP information, review for accuracy, and develop list.
- 1.03.04 Determine practices and confirm technology and methodology to establish MDOP.
- 1.03.05 Document MDOP establishment methodology (existing, new, acquired, and reactivated Subject Pipelines).
- 1.03.06 Establish and document pressure test procedure and documentation requirements.

- 1.03.07 Gather existing set point data (control valves, shutdown devices, compressors, connected lines/manifolds, and relief systems).
- 1.03.08 Establish and document criteria for pressure control and shutdown device settings.
- 1.03.09 Determine high-pressure scenarios based on surge pressure conditions or other variations.
- 1.03.10 Conduct surge pressure analysis to determine potential impact of high pressure scenarios.
- 1.03.11 Compare high-pressure, surge and worst-case scenarios to 100% of MDOP or less as determined for the specific pipeline segment or related and connected equipment.
- 1.03.12 If necessary, develop plan to change shutdown devices or device settings, control, or activation.
- 1.03.13 Make set point or equipment changes per plan.
- 1.03.14 Compare existing control valve set points to normal operating conditions, surge conditions, and emergency and worst-case operating conditions.
- 1.03.15 If necessary, develop plan to change pressure control settings, procedures, instrumentation or other equipment and logic.
- 1.03.16 Change control valve settings or equipment per plan.
- 1.03.17 Integrate pressure control, shutdown, and relief device settings into new MDOP listing, programs, procedures, or logic.
- 1.03.18 Develop and implement sustainable process to maintain MDOP listing and control setting list.
- 1.03.19 Define Management of Change ("MOC") criteria and approval process.
- 1.03.20 Implement check process and integrate into other MOC processes.

1.04 In-Line Inspection ("Smart Pigging" and Other Technology)

Scope

This Plan will improve Koch Pipeline Company's program to provide appropriate in-line inspection of the Subject Pipelines to the level of Necessary Industry Standard.

Plan Element Commitments

1. The Key Commitment is "To determine on an ongoing basis the Necessary Industry Standard for in-line inspection ("ILI"), and to acquire and use such technology and practices, or better".
2. Perform necessary and scheduled pipeline integrity and reliability surveys to that use ILI.
2. Conduct a review of the current technology and methodology and adopt the Necessary Industry Standard, or better.
3. Formalize the decision process to conduct an ILI. The process will include consideration of data from previous ILI, tool/pipeline segment compatibility, release history, cathodic protection history, bell-hole inspections, and/or risk assessment tools.

Activities Required

- 1.04.01 Review current technology and methodology to perform ILI.
- 1.04.02 Review existing Koch Pipeline Company guidelines and procedures, if any, and revise to meet and utilize the Necessary Industry Standard.
- 1.04.03 Review current practices and confirm methodology for ILI frequency and prioritization.
- 1.04.04 Establish and document the ILI decision process.
- 1.04.05 Conduct currently scheduled in-line inspections.

1.04.06 Conduct in-line inspections to meet overall condition assessment, ongoing operations and maintenance, and integrity and reliability Plans and goals.

1.04.07 Update and acquire knowledge of and technology and methodology as the ILI-related industry and services evolve and improve.

1.05 Pipeline Repair Practice

Scope

This Plan Element will improve Koch Pipeline Company's programs to provide appropriate repair practices for pipelines consistent with the Necessary Industry Standard.

Plan Element Commitments

1. Continue to remove or repair confirmed corrosion defects that affect safety and MDOP, arc burns, cracks, gouges, faulty welds, and dents. Continue to remove or repair confirmed dents that are at the seam or girth weld, or are deeper than 1/8-inch in pipe four-inch or less in nominal diameter, or are deeper than 6% of the outside diameter in pipe four-inch or greater in nominal diameter.
2. Continue to select repair methods based on an evaluation of the defect, history, risk assessment, and MDOP.
3. Formalize defect evaluation practices by establishing evaluation procedures and corresponding documentation requirements.
4. Defects and repairs will be evaluated and approved by a Qualified Person (See Plan 5.00.04, Training Plan for developed source of definitions of Qualified Person). Welding Inspectors of the Subject Pipelines will be qualified in welder qualification, radiographic technician qualification, and pipeline welding inspection as per the latest (and ongoing updated) AWS guidelines and test and qualification procedures, and at least qualified to level AR-2 (piping, moderate to high pressure, hydrocarbon and chemical environments).

Activities Required

1.05.01 Review current practices and confirm or upgrade repair criteria and methodology consistent with Necessary Industry Standard.

1.05.02 Establish repair documentation requirements.

1.05.03 Establish and document repair criteria, methodology, and documentation requirements.

1.05.04 Adopt subsequent editions of API 1104 and American Welding Society (“AWS”) guidelines as they are issued, updated, or amended.

1.05.05 Review current practices and confirm pipeline defect evaluation methodology.

1.05.06 Establish and document defect evaluation and documentation requirements, including record retention.

1.05.07 Establish requirements and qualification process for Qualified Persons and contractors (welding, repair, construction, excavation, trenching, line protection, coating evaluation, application, and protection, supervision, testing, and inspection).

1.05.08 Initiate a training process and qualify individuals (See Training Plan).

1.05.09 Qualify welding inspectors in welder qualification.

1.05.10 Qualify welding inspectors in pipeline welding inspection.

1.06 Cathodic Protection

Scope

This Plan element will improve Koch Pipeline Company’s programs to provide appropriate Cathodic Protection to control external pipeline corrosion to a level of the Necessary Industry Standard.

Plan Element Commitments

1. Perform surveys of the Subject Pipelines within each sixty-day period, annual surveys, and bell-hole inspections, with all surveys filed with the Auditor during the reporting and audit periods.
2. Perform pipeline assessment and risk analysis procedures including test point and close-interval surveys on all of the Subject Pipelines.
3. Conduct a review of existing practices and procedures and update as necessary to adopt and reflect Necessary Industry Standard.

Activities Required

- 1.06.01 Perform necessary procedures under assessment of condition program to conduct test point surveys.
- 1.06.02 Perform necessary procedures under assessment of condition program to conduct close-interval surveys ("CIS").
- 1.06.03 Review current documentation to support cathodic protection system operation.
- 1.06.04 Review current survey and remedial action work process.
- 1.06.05 Review current Cathodic Protection Standard and revise, as needed. Incorporate work processes and documentation practices and upgrade as necessary to adopt and reflect Necessary Industry Standard.
- 1.06.06 Review existing close-interval survey Technical Guideline and revise, as needed to adopt and reflect Necessary Industry Standard
- 1.06.07 Review existing pipeline casing Technical Guideline and revise, as needed.
- 1.06.08 Review systems developed to ensure inspections are completed on time.
- 1.06.09 Complete inspections on time as per the schedule here, regulations and Necessary Industry Standard.

1.07 Close-Interval Survey (CIS)

Scope

This Plan Element will improve Koch Pipeline Company's programs to perform close-interval surveys and will set and determine criteria for and a schedule for performing such surveys to the level of the Necessary Industry Standard.

Plan Element Commitments

1. To schedule and complete close-interval and specific test location surveys within a certain schedule.
2. Review existing methodology and technology used by Koch to conduct such tests and surveys.
3. Revise and update methodology and technology used by Koch to conduct such tests and surveys.
4. Determine and implement a procedure for the decision as to why, when, and how to conduct such tests and surveys.

Summary of Activities Required

- 1.07.01 Complete previously scheduled CIS with existing methodology, technology, and procedures.
 - 1.07.02 Review current Koch technology, methodology, and procedures and compare with Necessary Industry Standard; update as required.
 - 1.07.03 Review existing Koch CIS documentation.
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1.07.04 Review technology and methodology in industry, acquire, and implement to level of Necessary Industry Standard.

1.07.05 Implement documentation and decision/implementation decision tree or similar process techniques.

1.07.06 Integrate in MOC Plan and update on ongoing basis.

1.08 Internal Corrosion Control

Scope

This plan element will improve Koch Pipeline Company's programs to provide internal pipeline corrosion control to level of the Necessary Industry Standard.

Plan Element Commitments

1. Evaluate transported liquids and establish an applicable internal corrosion control program that consists of one or more of the following: maintenance, pigging, chemical treatment, and appropriate ongoing or increased monitoring.
2. Establish guidelines for product sampling location, bacteria and corrosive element criteria, determining the need for chemical treatment, selecting chemicals and treatment methods, maintenance pig selections and frequency, analysis of maintenance pigging residuals, coupon location, and type and frequency of monitoring.
3. Develop and initiate a Management of Change process for internal corrosion related variables.

Activities Required

1.08.01 Review current practices and confirm methodology.

1.08.02 Review current documentation (forms, software, etc.) to support internal corrosion control.

- 1.08.03 Establish and document methodology.
- 1.08.04 Establish documentation requirements.
- 1.08.05 Define MOC variables, criteria, and approval process.
- 1.08.06 Implement a check process and integrate into other MOC processes.
- 1.08.07 Review systems developed to ensure inspections are completed on time.

1.09 Atmospheric Corrosion Inspection

Scope

This Plan Element will improve Koch Pipeline Company's programs to provide corrosion control on aboveground sections of pipeline and related and attached and connected facilities, and underground pipeline segments that are exposed to atmospheric elements, with such improvement to the level of the Necessary Industry Standard.

Plan Elements Commitments

1. Formalize and gain consistency in current atmospheric corrosion inspection, evaluation, and determination of required remedial action.
2. Develop and initiate a program to conduct periodic inspections of aboveground pipe for atmospheric corrosion. This plan will establish maximum inspection frequencies of nominally three years (not to exceed 42 months).

Activities Required

- 1.09.01 Review current practices and confirm methodology to perform inspections.
- 1.09.02 Review current inspection documentation forms(s) and revise, as needed to achieve the Necessary Industry Standard.

- 1.09.03 Review current practices and confirm how to determine required remedial action.
- 1.09.04 Establish and document practices and methodology.
- 1.09.05 Update exposed pipeline listings.
- 1.09.06 Develop periodic inspection plan. Inspections not to exceed three years.
- 1.09.07 Develop MOC process to keep listing current
- 1.09.08 Initiate periodic inspection plan.
- 1.09.09 Review systems developed to ensure inspections are completed on time

1.10 Patrolling

Scope

This Plan Element will improve Koch Pipeline Company's programs to patrol its pipelines to a level of the Necessary Industry Standard.

Plan Element Commitments

1. Complete aerial patrolling at frequencies not to exceed three weeks, but at least 26 times a year.
2. Conduct ground patrols and inspections whenever construction or other activity that could reasonably present a hazard to a pipeline or related facilities is observed by the aerial patrols, observed by company employees, or reported to the company, formally or informally.
3. Formalize and gain consistency of current ROW inspection and patrolling practices, including documentation of each patrol and of pipeline markers consistent with condition criteria and marker location criteria found elsewhere in this document and to the Necessary Industry Standard.

Activities Required

1.10.01 Review current patrolling intervals, timing, procedures, follow-up, and documentation practices.

1.10.02 Establish and document patrolling procedures, methodology, and documentation requirements.

1.10.03 Establish and document maintenance and mowing procedures so that the used section of right-of-way where pipelines are located are readily determinable by observing the condition, appearance, and marking of the pipeline(s).

1.10.04 Review current ROW inspection practices, maintenance, mowing, and quality considerations.

1.10.05 Establish and document ROW quality criteria and methodology to determine inspection frequency.

1.10.06 Review systems developed to ensure patrolling is completed on time and modify, as needed.

1.11 Inactive and Abandoned Pipeline Management

Scope

This Plan Element will improve Koch Pipeline Company's programs to manage the abandonment and deactivation of the Subject Pipelines.

Plan Element Commitments

1. Ensure that proper abandonment/de-activation procedures have been and will be followed on the Subject Pipelines.
2. Ensure that proper procedures for returning an inactive or abandoned pipeline to service are in place and will be utilized for future applicable activities.
3. Ensure records of abandoned/ de-activated or inactive pipelines are appropriately maintained.

4. Ensure that records and a history of the line are accurately and timely provided to entities, included related parties, that purchase or assume operation of the abandoned or inactive line, including those returning the line to service or who might intend to return the line to service.

Activities Required

1.11.01 Conduct an inventory of abandoned or de-activated pipelines that are part of or connected to the Subject Pipelines.

1.11.02 Formalize requirements for abandoning/de-activating a pipeline, including pigging, Cathodic Protection, inspection, and ROW control, disconnection, line purge, seal-off, and monitoring.

1.11.03 Develop a plan to implement revised abandonment/de-activation procedures.

1.11.04 Formalize requirements for returning an inactive pipeline to service, including standards to inspect, test, and determine if the pipeline is in condition for safe operation, ROW requirements are current or met, and for establishing MDOP.

1.11.05 As necessary, develop a plan to implement revised procedures for returning an inactive pipeline to service.

1.11.06 Formalize requirements for maintaining records on abandoned or de-activated or inactive pipelines.

1.11.07 Develop a plan to implement revised procedures for returning an inactive pipeline to service.

1.11.08 Formalize requirements for maintaining records on abandoned/de-activated or inactive pipelines.

1.11.09 Develop a plan to correct existing records maintenance procedures.

1.11.10 Implement revised processes and integrate in MOC Plan.

B: PIPELINE MARKER AND COVER PROGRAM

2.00 Line Marker Placement and Maintenance

Scope

This plan will improve Koch Pipeline Company's programs to provide necessary identification and marking of the pipeline using Necessary Industry Standard.

Plan Element Commitments

1. Establish a pipeline marker placement methodology and condition criteria as per API RP 1109, with enhanced definitions for marker placement to require the markers to be placed within one foot of the pipeline, and with a marker identification system for quick, precise location of each marker.
2. Determine the current condition of markers and marker location and effectiveness. Upgrade the markers as required under this program and/or to Superior Industry Standard.
3. Formally and informally survey for required sign placement and condition during day-to-day operations and maintenance activities. Complete corresponding placement, replacement, and repair activities.
4. Develop and initiate an ongoing periodic marker placement and condition survey program. This program will establish inspection frequencies of nominally three years (not to exceed 42 months) for rural-no activity areas, ranging to inspection frequencies not to exceed six months where activity is likely.

Activities Required

- 2.00.01 Review current marker placement methodology, wording, and presentation.
- 2.00.02 Establish and document a marker condition methodology.

- 2.00.03 Establish and document marker condition criteria.
- 2.00.04 Establish and document marker survey documentation requirements
- 2.00.05 Develop a periodic marker placement and condition survey plan.
- 2.00.06 Initiate and complete an initial assessment survey.
- 2.00.07 Develop and implement an ongoing periodic marker survey plan.
- 2.00.08 Review systems developed to ensure inspections are completed on time and that the inspection procedure results in effective marker placement, repairs, and monitoring.
- 2.00.09 Coordinate this system of marker inspection, condition surveys, and maintenance with Patrolling plan.

2.01 Mapping Plan

Scope

This Plan Element will improve Koch Pipeline Company's programs to provide updated and accurate mapping and location of the Subject Pipelines and related facilities. The plan will include mapping to readily identify pipeline and valve locations to company employees, responders, landowners, other affected persons or stakeholders so that the pipeline can be readily identified and precisely located for purposes of emergencies, response, construction, leaks, or other situations that can be anticipated to require precise pipeline and depth location.

Plan Element Commitments

1. To accurately and precisely locate and accurately map and document the Subject Pipelines.
2. To have available and readily referenced, cataloged, or other systems in place to immediately, efficiently, and accurately locate the pipeline for anticipated purposes and situations.

3. To accurately and precisely locate and accurately map and document the Subject Pipelines, and all installed alarms, warning systems, or monitors on an ongoing basis.
4. To coordinate this plan with the Pipeline Marker and Patrolling plans.

Activities Required

- 2.01.01 Assemble and place in immediately usable formats and locations all existing pipeline maps, drawings, alignment sheets, landowner/lessor and right-of-way records, and as-built, repair, incident, one-call request/response, or leak information, locations, and data.
- 2.01.02 Develop a database of current data in immediately usable and accessible formats and locations.
- 2.01.03 Determine and adopt the technology and methodology for pipeline location, mapping, documentation, and information retrieval that is compatible with the Necessary Industry Standard, or better.
- 2.01.04 Map the Subject Pipelines and related or connected facilities, alarms, warning devices, and equipment using Necessary Industry Standard.
- 2.01.05 Communicate and coordinate with "One-call" databases and systems and with responders, landowners/lessors, and other affected persons and stakeholders to ascertain that the best use is made and available for safe operations and most efficient response to emergencies or similar situations that can be anticipated and planned for that might require the use of precise mapping and location data.
- 2.01.06 Maintain the mapping function and documentation at the attained level or better as technology and methodology is improved and upgraded in the industry.
- 2.01.07 Integrate in the MOC Plan.

2.02 Pipeline Depth-of-Cover Surveys

Scope

This Plan Element will allow Koch Pipeline Company to assess the Subject Pipelines and connected and related systems to determine the actual depth-of-cover or burial depth of the Subject Pipelines.

Plan Element Commitments

1. Determine the appropriate methodology and technology to assess the depth-of-cover for the Subject Pipelines to the level of the Necessary Industry Standard.
2. Determine the depth-of-cover of the Subject Pipelines.
3. Determine what remedial action is required to safely operate the pipeline.
4. Monitor depth of cover on an ongoing basis, including changes or variables on the system.

Activities Required

- 2.02.01 Assess the available technology and methodology for properly conducting accurate depth-of-cover surveys.
- 2.02.02 Determine the technology and methodology to be utilized for depth-of-cover surveys to the level of Necessary Industry Standard.
- 2.02.03 Conduct a depth-of-cover survey for the Subject Pipelines, on a close-interval and precise basis.
- 2.02.04 Use the data acquired as part of the Mapping Plan.
- 2.02.05 Use and document the data acquired as a base-line for future MOC considerations.
- 2.02.06 Develop and ongoing program for depth of cover monitoring and surveys, including consideration for land use, nearby activity, erosion, and other factors.

2.03 Exposed Pipe Identification Survey and Evaluation

Scope

This Plan Element will improve Koch Pipeline Company's programs to provide appropriate identification and evaluation of exposed pipe.

Plan Element Commitments

1. Continue to maintain a listing of the locations of identified exposed pipeline.
2. Conduct a survey of the Subject Pipelines to further identify locations of exposed pipeline.
3. Establish procedures to evaluate exposed pipelines. These procedures will include the determination of necessary remedial action, the installation of pipeline markers or special/specific pipeline markers, lowering, redirecting, or removing sections from service, and appropriate re-evaluation, follow-up, and monitoring, as necessary.
4. Develop and initiate a plan to conduct periodic exposed pipe identification surveys. This plan will establish inspection frequencies of nominally three years (not to exceed 42 months) for rural-no activity areas, ranging to inspection frequencies not to exceed six months where activity is observed, reported, or where development or construction can be reasonably determined to exist.

Activities Required

- 2.03.01 Determine and document exposed pipeline listing requirements.
- 2.03.02 Review current exposed pipeline evaluation practices.
- 2.03.03 Establish and document exposed pipeline evaluation procedure and documentation requirements to the level of the Necessary Industry Standard.
- 2.03.04 Conduct exposed pipeline identification surveys and perform remedial action, if required.

- 2.03.05 If pipeline will remain exposed, place pipeline markers, install barriers or protection, or other appropriate action, and schedule next inspection.
- 2.03.06 Develop plan to conduct periodic exposed pipeline evaluation surveys.
- 2.03.07 Develop MOC process to keep listing current.
- 2.03.08 Initiate an ongoing periodic survey plan.
- 2.03.09 Review systems developed to ensure inspections are completed on time.

2.04 Water Crossing Inspection

Scope

This Plan Element will improve Koch Pipeline Company's programs to inspect and evaluate pipelines and pipeline right-of-ways at water crossings.

Plan Element Commitments

1. Continue observing water crossings during aerial patrolling and formally and informally inspect crossings during other maintenance and operations activities.
2. Continue to inspect at least every two years (using divers, probe or jet rods, depth profile surveys, or another comparable methods) each pipeline crossing under navigable waterways or where there is a reasonable likelihood of commercial navigation.
3. Develop and initiate a plan to conduct visual water crossing inspections for conditions that might affect the safety and security of the crossings. This plan will establish inspection frequencies of nominally three years (not to exceed 42 months) for rural-no activity areas, ranging to inspection frequencies not to exceed six months where activity is observed, reported, or where development or construction can be reasonably determined to exist.

4. During such conditions as drought, increased rains or flooding, inspect and monitor water crossings to determine if changed conditions might affect the system.

Activities Required

- 2.04.01 Determine and map navigable waterways and all other water crossings.
- 2.04.02 Establish criteria for reasonable likelihood of commercial navigation in other or developing waterways.
- 2.04.03 Review list of water crossings with likelihood of commercial navigation and revise, as needed.
- 2.04.04 Review current methods of inspection of water crossings with commercial navigation and for all other waterways.
- 2.04.05 Establish and document methodology of inspections using Necessary Industry Standard.
- 2.04.06 Establish water-crossing design, construction, inspection, and maintenance criteria.
- 2.04.07 Create a water-crossing list for all water crossings.
- 2.04.08 Develop guideline for visual identification of conditions effecting safety or security of water crossings.
- 2.04.09 Develop and document a plan to conduct periodic visual inspections of water crossings.
- 2.04.10 Develop MOC process to keep listings current and to assess changes at or near water crossings that might affect criteria or determinations.
- 2.04.11 Initiate periodic visual inspection plan.
- 2.04.12 Review systems developed to ensure inspections are completed on time.

2.05 Road Crossing Inspection

Scope

Same type of criteria as for Water Crossing Inspection plan.

Plan Element Commitments

Same type of criteria and goals as for Water Crossing Inspection plan.

Activities Required

Same type of activities as for Water Crossing Inspection plan. Utilize API RP 1102.

2.06 Railroad Crossing Inspection

Scope

Same type of criteria as for Water Crossing Inspection plan.

Plan Element Commitments

Same type of criteria and goals as for Water Crossing Inspection plan.

Activities Required

Same type of activities as for Water Crossing Inspection plan. Utilize API RP 1102.

2.07 Land Use and Activity Evaluation

Scope

This Plan Element will establish a protocol and criteria for initial assessment of

right-of-way and surrounding land use. The element will determine anticipated development and activity that could affect such factors as proximity and population density, and potential contact with the pipeline or right-of-way due to development and construction.

Plan Element Commitments

1. Develop criteria for determining land use and activity database elements and variables to the level of the Necessary Industry Standard.
2. Monitor potential changes, land uses, and activity on an ongoing basis.

Activities Required

2.07.01 Develop criteria, definitions, and protocol for land use, activity, and associated changes and risk. Develop similar to environmental impact protocol but for land use, development, or other activity that can affect the pipeline and right-of-way and nearby properties.

2.07.02 Coordinate with Mapping Plan to document and create database for current use.

2.07.03 Document and monitor changes in land use and activity; and potential activity on an ongoing basis.

2.07.04 Coordinate with initial assessment, risk analysis/assessment, and MOC plans.

2.08 Barriers and Protection

Scope

This Plan Element will require Koch Pipeline Company to access the risk of exposure and damage of the subject pipelines from encroachment and damage due to vehicles or other known or anticipated activity. Barriers, shields, or engineered covers will be developed and installed where indicated. The risk assessment of surrounding activity, public presence, and such facilities as schools will be included.

Plan Element Commitments

1. Determine the risk of encroachment on the pipeline that can be prevented or decreased due to engineered barriers and fabricated or installed solutions.
2. Some facilities, such as above-ground piping and valves, may be relocated, removed, or re-engineered.
3. Risk assessment will be used to determine which facilities to treat under this element.

Activities Required

- 2.08.01 Develop risk assessment and criteria for barriers or other devices to prevent encroachment on the pipeline and facilities.
- 2.08.02 Follow the requirements of the Railroad Commission of Texas Barbers Hill / Mont Belvieu operating and field rules for the placement of barriers, or better technology based on the Necessary Industry Standard.
- 2.08.03 Integrate into MOC program for variables including changing land use and such factors as highway construction or nearby facility expansion or increased use.

C: STAKEHOLDER WARNING PROGRAM

3.00 Public Information

Scope

This Plan Element will improve the Koch Pipeline Company Public Awareness programs and plan. An improved plan with emphasis on public information as to hazards, improved response, and adoption of Necessary Industry Standard-based communication methods and technology.

Plan Element Commitments

1. To improve Public Awareness program database, land/right-of-way owner/user, and emergency and responder information.
2. Determine methods to improve actual communication and use of information and that persons actually receive accurate, timely, and usable information.
3. Implement ongoing updating of database and information, along with ongoing adoption of new technology and methodology for system to sustain Necessary Industry Standard.

Activities Required

- 3.00.01 Determine Necessary Industry Standard for database development and improvement for identifying, tracking, and communicating with affected or potentially affected owners, lessors, lessees, surface tenants, and nearby and adjacent affected persons, responders, and other stakeholders.
- 3.00.02 Adopt appropriate technology and methodology.
- 3.00.03 Develop database with aggressive MOC element.
- 3.00.04 Using API Recommended Practice as a baseline document, upgrade Public Awareness program to improve effectiveness and actual communication and awareness of potential hazards, the location of pipelines, warning and alarm methods, precautions, and the appropriate response.
- 3.00.05 Ongoing upgrading of system based on surveys and analysis of effectiveness and results of communication methods, printed materials, and other means of communicating information to stakeholders.
- 3.00.06 Improve contractor and third-party communication and awareness.
- 3.00.07 Coordinate Public Awareness and Public Information Plan with Mapping Plan, Marker Plan, and contractor program.
- 3.00.08 Develop ongoing program to determine and analyze variables, and integrate into MOC Plan.

3.01 Alarm Technology Assessment

Scope

This Plan Element will require Koch Pipeline Company to analyze technology and methodology to provide local alarms and warnings. These systems will be placed in each affected or potentially affected dwelling, business, and public place, with other alarms and warnings developed for critical vehicles such as for responders and school buses, etc.

Plan Element Commitments

1. Available technology and methodology will be surveyed to develop criteria and a protocol for alarm and warning system design to a level of the Necessary Industry Standard.
2. A system will be selected, designed, and implemented for installation in stakeholder accessible and usable form for alarm, warning, information, and response purposes to improve safety of affected or potentially affected person.

Activities Required

- 3.01.01 Survey technology and methodology available.
- 3.01.02 Select and design system.
- 3.01.03 Develop a criteria for selecting alarm and warning system installation locations.
- 3.01.04 Develop a criteria for alarm and warning system maintenance and periodic testing.
- 3.01.05 Develop a protocol and criteria for the use of and information to be conveyed and communicated with and by the system.
- 3.01.06 Implement a test program to determine system variables and to fine tune the system, installation, design, and use criteria and protocol of the system use.
- 3.01.07 Monitor system and technology on an ongoing basis.

3.01.08 Determine variables and integrate in MOC system.

3.02 Alarm and Warning System Implementation

Scope

This Plan Element will require Koch Pipeline Company to implement a system for local, area-specific, and site-specific alarms and warnings for events that occur related to the Subject Pipelines.

Plan Element Commitments

1. A system will be installed and maintained by Koch Pipeline Company similar to those systems used for weather warnings and for releases at chemical plants in the Houston Ship Channel and Corpus Christi, Texas areas, among others.
2. On an ongoing basis, the Mapping Plan and Public Information databases and information will be utilized to update the system and alarm and warning locations and installations.
3. The location of and requirement of alarm and warning systems and information will be integrated in the MOC Plan.

Activities Required

- 3.02.01 Implement the system for the Subject Pipelines.
- 3.02.02 Monitor the effectiveness of the system on an ongoing basis.
- 3.02.03 Determine and maintain the Necessary Industry Standard on an ongoing basis.
- 3.02.04 Integrate the system and ongoing analysis in the MOC Plan.

3.03 One-Call Implementation

Scope

This Plan Element will adopt the policy of Koch Pipeline Company to be a member of and participate fully in "One-Call" systems and similar programs, methodology, and technology in areas of operations of the Subject Pipelines, and to implement same to the level of the Necessary Industry Standard.

Plan Element Commitments

1. To adopt a policy to participate, and to implement the program participation.
2. Integrate this Plan with mapping, marker, emergency response and other plans as appropriate.
3. Integrate into MOC and sustain the Necessary Industry Standard.

Activities Required

- 3.03.01 Adopt policy to participate.
- 3.03.02 Design a plan using the Necessary Industry Standard.
- 3.03.03 Implement the program, including a documentation and employee training element in encroachment hazards and such factors as construction methodology and how such activity can affect the Subject Pipelines.
- 3.03.04 Sustain program and participation on ongoing basis to level of the Necessary Industry Standard.
- 3.03.05 Integrate into ongoing MOC Plan.

D: LEAK DETECTION PROGRAM

4.00 Leak Detection Plan

Scope

This Plan Element will improve Koch Pipeline Company's programs to provide appropriate leak detection methods, equipment, and procedures; and reduce detection and response time and solutions in the event of a leak or release. The Key Commitment is to "Apply the Necessary Industry Standard or better to provide leak detection, instrumentation, response, and documentation on the Subject Pipelines."

Plan Element Commitments

1. Conduct an assessment and evaluation to ensure the appropriate method(s) of leak detection is or will be installed on the Subject Pipelines.
2. Validate the system and compliance with the Necessary Industry Standard and make appropriate revisions to the design, operation, maintenance, and testing of the existing leak detection systems.
3. Develop a process to ensure pipeline changes are appropriately updated in leak detection systems.
4. Improve procedures and systems to estimate pertinent incident information, such as release location and volume; and what response should be to changes in the area of the Subject Pipelines over time.

Activities Required

- 4.00.01 Gather information on current leak detection methods applied to Subject Pipelines.

- 4.00.02 Define criteria to determine leak detection method(s) that should be applied on the Subject Pipelines in conformance with API 1130 and the Necessary Industry Standard.
- 4.00.03 Evaluate Subject Pipelines against weighted criteria and formalize leak detection requirements.
- 4.00.04 Develop plan to implement leak detection system changes as required.
- 4.00.05 Implement and complete changes in leak detection and response systems.
- 4.00.06 Identify Subject Pipeline changes and changes in the area of the Subject Pipelines that impact the operation of leak detection and response systems.
- 4.00.07 Formalize requirements for estimating pertinent incident information, such as estimation of leak volume, leak location, leak rate, pressure at leak site, and leak time.
- 4.00.08 Develop a plan to implement revised response to leaks based on new formalized leak estimating requirements.
- 4.00.09 Formalize requirements for reporting changes and define procedures for updating the leak detection systems based on those changes.
- 4.00.10 Implement process improvements based on changes that occur; with integration into MOC Plan.
- 4.00.11 Implement revised estimating procedures based on changes that occur; with integration into MOC Plan.

4.01 Pressure Monitoring and Recording Equipment

Scope

This Plan Element will improve Koch Pipeline Company's programs to evaluate, update, and implement the selection, installation, maintenance, and operation of

pressure monitoring and recording equipment. This is a critical system for detecting leaks and other system operations monitoring.

Plan Element Commitments

1. Ensure that the appropriate technology, methodology, and type of pressure monitoring and recording equipment has been installed at necessary locations for safe pipeline operation and in accordance with the Necessary Industry Standard.
2. Ensure that appropriate pressure data is available for required operations personnel to ensure safe operation and is in a usable format to conform to new leak detection procedures and requirements of other Plans in this Program.
3. Ensure that maintenance and inspection of pressure monitoring and recording equipment are performed within schedule guidelines.
4. Update equipment and procedures as required to maintain the Necessary Industry Standard.
5. Integrate the pressure monitoring and equipment into MOC.

Activities Required

- 4.01.01 Conduct an inventory of existing pressure monitoring and recording equipment and gather information on existing installation practices.
- 4.01.02 Determine the capability of existing equipment, logic, and such factors as control room display, alarms, and usefulness to function with the new leak detection program.
- 4.01.03 Formalize requirements for pressure equipment selection, installation, use, maintenance, and procedures on the Subject Pipelines to conform to the Necessary Industry Standard.
- 4.01.04 Evaluate existing selection and installation practices with the new determined requirements.
- 4.01.05 Develop a plan to install additional equipment or new methodology or technology to upgrade existing pressure equipment as needed.

- 4.01.06 Implement the program with new equipment and upgrades in the system as required.
- 4.01.07 Define existing processes for capturing, storing, retrieving, and utilizing pressure data.
- 4.01.08 Formalize requirements for capturing, retrieving, storing, and utilizing pressure data on all Subject Pipelines using the Necessary Industry Standard and to conform to new leak detection and response requirements.
- 4.01.09 Define current inspection, maintenance, repair, and documentation practices for pressure monitoring/recording equipment.
- 4.01.10 Formalize requirements for inspection, maintenance, repair, and documentation practices for pressure monitoring recording equipment on the Subject Pipelines to achieve the Necessary Industry Standard.
- 4.01.11 Implement the plan for data acquisition, use, and management.
- 4.01.12 Implement revised equipment maintenance and inspection processes as necessary.
- 4.01.13 Integrate these elements into the MOC Plan.

4.02 Release Tracking

Scope

This Plan Element will improve Koch Pipeline Company's programs to appropriately track pipeline releases to the level of Necessary Industry Standard.

Plan Element Commitments

1. Improve the process to track releases.
2. Maintain a release database to track and document all leaks and releases, whether agency-reportable pipeline releases or of smaller estimated volumes to achieve both compliance with minimum standards and to develop and maintain a database for historical, future assessment of the Subject Pipelines and to integrate

into the MOC Plan.

Activities Required

- 4.02.01 Review existing release tracking system and related processes.
- 4.02.02 Formalize requirements for tracking appropriate leak and release information for all estimated volumes.
- 4.02.03 Update current release tracking database as required to include and maintain the information outlined in the leak detection and monitoring plan to be implemented here.
- 4.02.04 Implement revised tracking procedures according to the formalized requirements.
- 4.02.05 Achieve the Necessary Industry Standard and integrate into MOC on an ongoing basis.

E: TRAINING PLAN

5.00 Training Plan

Scope

This plan will develop and implement a formal training program throughout the Subject Pipelines. The program will include training on corrosion control, leak detection and prevention, emergency response operations, pipeline systems operation and maintenance, reporting, applicable state regulatory requirements, and environmental risk management. The Key Commitment is to, "Develop, implement, and sustain a systematic training program to ensure and document that activities required for integrity and reliability on the Subject Pipelines and to achieve and maintain the Necessary Industry Standard are performed by qualified personal."

Plan Element Commitments

1. Develop a training program to qualify employees to perform various duties on the pipelines. This will include operator qualification to meet minimum regulatory requirements, as well as duties required to perform corrosion control, leak detection and prevention, emergency response operations, pipeline systems operation and maintenance, reporting, applicable state regulatory requirements, and environmental risk management to a level of the Necessary Industry Standard.
2. Employees who work on the pipelines will attend at least annual training on the Operations and Maintenance manual for their area.
3. All employees will be treated as though they are “employees who may respond to an incident”, and will attend at least annual training on the Emergency Response manual for their area. Control room supervisors and workers will be familiar with all elements of the mapping, monitoring, leak detection, and response plans for all areas of the Subject Pipeline operations. Historical leak detection shortcomings, leak scenarios, and other practical methods will be integrated into the training system.
4. All employees involved in pipeline monitoring, controlling, training, and operations and maintenance will also participate in drills on the response plans.
5. Verify and document that contractors are qualified to perform tasks as appropriate after developing methodology to do so.
6. Update training methodologies and technologies and integrate into the MOC Plan on an ongoing basis to the level of the Necessary Industry Standard

Activities Required

- 5.00.01 Evaluate and Assess existing training plans and programs as compared with the Necessary Industry Standard.
- 5.00.02 Develop and upgrade overall training program and criteria including for contractors.
- 5.00.03 Develop training documentation criteria and other tools.
- 5.00.04 Develop documentation system and tools.

- 5.00.05 Define clear criteria for operations and maintenance tasks requiring training, and definitions of such factors as "qualified" and "trained" persons.
- 5.00.06 Develop method to identify and identify tasks.
- 5.00.07 Continue participation in industry and commercial programs on employee training and qualification criteria, methods, and curriculum.
- 5.00.08 Identify qualifications for trainers/qualifiers under the program.
- 5.00.09 Develop procedures outline and guidelines.
- 5.00.10 Write procedures and training guidelines.
- 5.00.11 Review and verify procedures with employees and field testing input or methodology.
- 5.00.12 Identify trainers and qualifiers.
- 5.00.13 Develop implementation strategy/program.
- 5.00.14 Develop retraining/qualification criteria.
- 5.00.15 Identify tasks on which individuals will need to be qualified.
- 5.00.16 Training for trainers/qualifiers as necessary.
- 5.00.17 Write program for training/qualification program.
- 5.00.18 Review Operations & Maintenance ("O&M") manual for existing training and implementation required.
- 5.00.19 Review and develop O&M Training template and format.
- 5.00.20 Write training materials for O&M by task and section.
- 5.00.21 Circulate materials for review and update rework as necessary.
- 5.00.22 Finalize training material.
- 5.00.23 Survey current training materials for emergency response plan.

- 5.00.24 Develop needed training materials as required for emergency response.
- 5.00.25 Survey current emergency drill schedule and programs as required.
- 5.00.26 Develop emergency drill schedule and programs as required.
- 5.00.27 Develop contractor qualification process.
- 5.00.28 Train on minimum regulatory tasks upgraded to Necessary Industry Standard as appropriate and necessary.
- 5.00.29 Train on O&M manual on frequent and ongoing basis, with all sections covered at least annually.
- 5.00.30 Train on emergency response plan on frequent and ongoing basis, with entire plan covered at least annually.
- 5.00.31 Emergency responses drills will be conducted as necessary for proficient performance.
- 5.00.32 Retrain as required by each training element and to achieve a level of performance, qualification, and employee knowledge that meets the Necessary Industry Standard.
- 5.00.33 Define verification process to integrate with work management and employee evaluation.
- 5.00.34 Integrate training into ongoing MOC Plan.

F: LONG-TERM PIPELINE PLANS

6.00 Management of Change Plan (MOC)

Scope

This Plan Element will require Koch Pipeline Company to develop and implement a plan and document for properly, timely, and appropriately dealing with changes in variables that affect the Subject Pipelines, that keeps the level of safety and performance at or above minimum regulatory requirements and conforms with the Necessary Industry Standard.

Plan Element Commitments

1. Determine Necessary Industry Standard and methodology for MOC.
2. Implement MOC for the Subject Pipelines on an ongoing basis.

Activities Required

- 6.00.01 Evaluate and determine available methodology.
- 6.00.02 Select methodology to utilize.
- 6.00.03 Implement the MOC Plan.
- 6.00.04 Verify MOC effectiveness on an ongoing basis; with changes in MOC as dictated to sustain level of Necessary Industry Standard.

G: BUDGET FOR PROGRAM

7.00 Budget For Program

Scope

This Plan Element will require Koch Pipeline Company to develop and implement a budget and actually expend, based on the timetable given below and on the performance schedule given above.

Plan Element Commitments

1. Koch Pipeline Company will reserve, budget, and allocate at least the amounts shown below, and in a proportional fashion as presented here. If the funding for one area is reasonably required to be increased based on specifications, bids, or obtained cost estimates when planning or beginning the work, that specific cost or category will be increased in this Plan Element Commitment without decreasing the amount or relative proportion of other specific budget items or categories.
2. Koch Pipeline Company will actually spend the indicated or greater required amounts each calendar year beginning the first calendar year or reporting year as set forth above, and the budget process and expenditures will be built into the Auditor's enforcement mechanisms.

Activities Required

7.00.01 Tabular Budget Below

Table 3: Budget For Program

Amount of Expenditure
Shown in \$ / Mile of Subject Pipeline

(Thousands of Dollars)

<u>Category/Line</u>	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>
Program-Develop					
Koch	15	12	9	9	9
Auditor	10	5	5	5	5
Program-Implement					
Assessment-Pipe	12	6	0	0	0
Document ^a	5	3	0	0	0
Database ^b	2	2	2	2	2
Alarm/Warning	10	7	5	5	5
Recondition (30%) ^c	60	60	0	0	0

^a Includes mapping, cover, marker assessment

^b Includes public information, ROW records, survey, inspection, marker program documents

^c Total cost to recondition is estimated at \$ 120,000 per mile, allocated over two years of work to implement fully; with 30% of system reconditioned as per test/inspect/repair criteria. Reconditioning includes such aspects as upgrading and replacing corrosion control, implementation of marker program, etc.

Continued – Table 3: Budget For Program

Replace (15%) ^d	200	200	0	0	0
Training	15	10	6	6	6
Auditor	7	7	5	5	5
\$ / Mile Total	336	312	18	18	18

^d Total cost to replace pipeline is estimated at \$ 400,000 per mile, allocated over two years of work to implement fully, with 15% of system replaced

APPENDIX A

Table 1: Definitions

Subject Pipelines: The Subject Pipelines are all pipelines, other than crude oil pipelines, that are owned, in whole or part, or operated, in whole or part, by Koch Pipeline Company or related entities, affiliates, or subsidiaries. A related entity includes any pipeline operation, group, partnership, limited partnership, system, or business relationship in which Koch or related entities have 50 % or more ownership, have operating rights, or have a significant representation on the board of directors or similar management influence or representation. The term Subject Pipelines includes related and connected facilities including but not limited to compressor stations, pump or booster stations, processing facilities, metering facilities, pig launchers and receivers, above-ground installations connected to the pipeline, instrumentation, control rooms or centers, communication systems used for or connected to the pipelines, and other related equipment and facilities which function to operate, control, or monitor the pipeline and any related equipment and activities.

Necessary Industry Standard: The Necessary Industry Standard is defined here for Koch Pipeline Company. The Necessary Industry Standard is a standard within the range of and scope of the industry standard, and is a standard that is (1) at least as high as minimum Federal and State pipeline and other related safety regulations, and (2) that evidences use of the best methodologies and technologies that are feasible, that are currently available to the industry, and that are used in the industry. This standard does not require the development of new methodologies or technologies, and is not a Best Available Technology standard, and does not include experimental methodology or technology. The Necessary Industry Standard does however require the use of methodology and technology that is better than what some companies use in the industry, which could be stated as some level of “industry standard” but not a “high” or “better” industry standard. At times government regulations reflect requirements that are above the industry standard; and at times regulations and the methodology and technology in those regulations is relatively outdated and “behind-the-curve” relative to what is feasible, available, and in use.

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This definition and the principle of Necessary Industry Standard is in conformance with the principles set forth in both the United States DOT/OPS regulations and in the 1996 API RP 1129, "Assurance of Hazardous Liquid Pipeline System Integrity" and especially as related to pipeline safety. (See attached as Exhibit A-1, and specifically at Section 5, several pages of which are attached at front of exhibit with emphasis added).

First, the DOT/OPS regulations (and as adopted by some states, such as at 16 T.A.C. in Texas) are minimum standards that allow the use of standards and practices above the minimum specified regulations, standards, practices, and design criteria. In certain circumstances even the DOT/OPS standards require that the minimum standards be exceeded to be in compliance. For example, this situation occurs under certain circumstances or situations that are covered by the "Safety-related Condition" provisions of the DOT/OPS regulations (See for example 49 CFR 195.400, attached as Exhibit A-2). A "Safety-related Condition" is any condition or circumstance that under stated conditions or in a stated situation requires reasonably immediate correction. A recent OPS opinion, for example, classified an older pipeline that was laid in 1942 at a cover depth of some 8-inches, as a "Safety-related Condition" where continuing development, changing land use, and other encroachment near the pipeline, rendered the amount of cover unsafe even though technically the subject pipeline cover depth was "grandfathered" because the pipeline was laid before the Federal regulation was put in place in 1969 (See attached as Exhibit A-3 as an example). In this instance, the cover depth is treated as an "Operations and Maintenance Issue" for continued safety rather than the construction provision which is grandfathered. In summary, any "Safety-related Condition" affecting pipeline safety may require use of standards, practices, or procedures that are above the regulatory minimum.

Second, the American Petroleum Institute ("API") generally reflects industry opinion and practice and one of its stated purposes is to do so. In 1993, the API and Office of Pipeline Safety ("OPS") entered into a formal Joint Government / Industry Initiative to study ways to improve the integrity of pipeline systems. The result of this study, after meetings and the solicitation of industry and other stakeholder input,

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was the 1995 final report entitled "Risk Management Within The Liquid Pipeline Industry".

(See cover page attached as Exhibit A-4). This report studied information based on a series of questions which address risk management and risk assessment techniques and their application to the pipeline industries. In the "action" section of the report, it was determined that (1) API should develop a risk-based Recommended Practice, and, (2) that OPS should develop risk management related regulations (See attached page as Exhibit A-5). Both of these elements were accomplished and are continuing. API responded relatively quickly in terms of historical development of API materials, by issuing API RP 1129 in August, 1996, only one year after the Joint Initiative final report. OPS responded by issuing a report on risk management and proposing rules for increased risk management in "high-risk" areas (population increase, encroachment, construction, etc.) and in environmentally sensitive areas, which effectively applies new operating rules to "grandfathered" construction (See attached as Exhibit A-6). Additionally, OPS established an ongoing Pipeline Risk Management Demonstration Project that has placed in the implementation phase many of the requirements set forth in this document. As an additional consideration, the American Society of Mechanical Engineers ("ASME"), in its code for pressure piping, B31.8-1995, "Gas Transmission and Distribution Piping Systems", which is adopted by reference in the DOT/OPS regulations, emphasizes that the regulations are not inclusive of all considerations that must be considered or how to consider all of those elements (See some examples attached as Exhibit A-7). The ASME publication has updated its definitions for some terms and location classifications for pipeline pressure/wall thickness/material design criteria to reflect the same principles as in the API/OPS Initiative, including applying new classification requirements to existing pipelines.

In summary, the API and OPS have adopted risk management for existing pipeline systems as one method to state the necessity for and to help define the Necessary Industry Standard for safety, reliability, and integrity in the pipeline industry.

EXHIBIT A – 1

- a. Weight loss coupons.
- b. Electrical probes.
- c. Galvanic probes.
- d. Hydrogen probes.
- e. Visual inspections.
- f. Test spools.
- g. Ultrasonic inspections of the pipe wall thickness measured externally.
- h. Ultrasonic and magnetic flux leakage internal inspection devices.
- i. Radiography.
- j. Water chemistry.

Water chemistry tests include:

- a. Iron concentration.
- b. Manganese concentration.
- c. pH.
- d. Bacteria levels.

- e. Oxygen levels.
- f. Carbon dioxide levels.
- g. Hydrogen sulfide levels.
- h. Chloride levels.
- i. Sulfate levels.
- j. Inhibitor residual.

If chemical inhibitor is used, DOT requires that the operator use coupons or other monitoring techniques to determine the effectiveness of the inhibitor. 49 *CFR* 195.418 requires corrosion coupons to be removed and examined at intervals not exceeding 7.5 months, but at least twice per calendar year.

All pipe removed from the pipeline system shall be inspected for internal corrosion damage and the results are typically documented. Refer to 49 *CFR* 195.418 (d).

Information from monitoring of internal corrosion activity shall be used to make adjustments to the internal corrosion control program as required.

SECTION 5—INSPECTION AND REVIEW

5.1 General

An inspection and review process should be developed to assure not only compliance with applicable regulations but also to extend assurances of overall integrity for the pipeline system. Inspection and review procedures in this section will be confined to those directly related to integrity assurance, but it should be recognized that numerous other inspections, reviews and audits are necessary and/or required in the areas of safety, industrial hygiene, and environmental protection.

5.1.1 REGULATORY REQUIREMENTS

The following DOT regulations (49 *CFR* Part 195) clearly spell out minimum inspection requirements and inspection frequencies in several key areas as follows:

- a. 195.412 Inspection of ROW and crossings under navigable waters.
- b. 195.414 Corrosion control (refer to Section 6).
- c. 195.416 External corrosion control.
- d. 195.418 Internal corrosion control.
- e. 195.420 Valve maintenance.
- f. 195.428 Overpressure safety devices.
- g. 195.432 Breakout tanks.

Other agencies including USCG, EPA, state and local jurisdictions may require inspections. It is incumbent on pipeline operators to assess and determine the applicability of regulatory requirements beyond those contained herein.

5.1.2 ADDITIONAL OPERATION AND MAINTENANCE INSPECTIONS

Integrity assurance practices should extend beyond these minimum required activities. Additional operation and maintenance inspections should be designed to include the following:

- a. Clear definitions of what is to be inspected.
- b. Determination of methods to comply with inspection frequency requirements.
- c. Performance measures, action plans and other documentation.
- d. Appropriately designed and used forms to facilitate such inspections.
- e. Training and deployment of qualified individuals to perform the inspections.

5.2 Risk Assessment

Risk assessment is an evaluation technique which attempts to define the most important factors that could lead to future problems through combination of statistical data, experience, and other resources. Such an assessment can become an effective means to identify and prevent problems (proactive) rather than to reacting after they have developed or occurred.

5.2.1 ANALYSIS

Risk evaluation can follow numerous approaches from sophisticated, highly data-oriented systems to more simple models, based on historical information and experience. Any

analysis should include the factors that are deemed to contribute to pipeline failures. The more significant failure contributors include:

- a. Third party damage.
- b. Corrosion.
- c. Operating errors.
- d. Manufacturing defects.
- e. Design/construction flaws.

Each of these factors could in turn include risk related items peculiar to that contributor.

5.2.1.1 Consequences

Consequences of failures should also be included in the analysis. Such factors must be included due to their potential impact on:

- a. Public and personnel health and safety.
- b. Environmental damage.
- c. Property and/or asset losses.

5.2.2 RESULTS

Through the combination and examination of all factors, using scoring/modeling techniques, the highest risk areas can be determined. Prioritizing or ranking of actions, including expenditures of funds or other resource allocations, can then be developed to address the higher risk areas first.

5.3 Hydrostatic Testing

5.3.1 GENERAL

49 CFR 195 Subpart E: "Pressure Testing" establishes minimum requirements for pressure testing various pipelines. API RP 1110 provides additional information to be considered during pressure testing. Refer also to ASME B31.4.

For integrity assurance purposes, hydrostatic testing is only one of the methods available to establish a pipeline's performance capability. Pipeline operators should also review appropriate integrity assurance measures, such as close interval surveys, internal pipeline inspections, and MOP reduction in addition to hydrostatic testing. Hydrostatic testing is used to verify structural integrity and the capability for containment of fluid. Hydrostatic testing used in combination with other inspection methods can provide an indication of the overall pipeline condition with excellent assurance of integrity.

49 CFR 195.303 defines the minimum test requirements to be at least a 4-hour continuous period at 125 percent or more of MOP (with an additional 4 continuous hours at 110 percent of MOP for pipelines that are not visually inspected for leakage), including written certification that documents the pressure recording, pressure calibration, and any reconciliation which validates the test. Hydrostatic testing provides a practical means to test the integrity of pipe, longitudinal seam

welds, if any, and to a lesser extent girth welds. In addition to hydrostatic testing, proof pressure testing checks may be conducted on an existing pipeline or piping segment for shorter durations during routine shutdown periods at sufficient pressure levels to assure leak tightness.

5.3.2 EFFECTIVENESS

While a hydrostatic test provides a demonstration of the current minimum pressure rating of a pipeline system, certain defects or imperfections and their characteristics must be considered. Defects which are currently large enough to cause failure at pressure levels up to and including the test pressure will usually be revealed and eliminated. Consequently, the higher the ratio of test pressure to MOP, the more effective the test is at documenting a pipeline's integrity because the difference between the sizes of defects that can remain after the test and those which would fail at the MOP becomes ever larger. A practical upper limit on test pressure is imposed by the need to avoid expanding or damaging otherwise sound pipe and/or its protective coating. Experience has shown that the minimum test pressure-to-operating pressure ratio imposed by the federal regulations (namely, 125 percent) provides an adequate demonstration of current pipeline integrity.

It is important to recognize certain limitations of hydrostatic testing. These limitations include:

- a. Anomalies or imperfections that are too small to fail a test pressure will not be revealed.
- b. Small defects that may become larger during subsequent operation of the pipeline could eventually become large enough to fail.
- c. Defects with failure pressures at or slightly above target test pressure that may become enlarged during the test without failing.

These latter defects may subsequently fail at pressure levels below that of the test which negates some of the margin of safety established by the hydrostatic test. This phenomenon is called a "pressure reversal."

CAUTION: Pipeline operators should be aware of the potential for pressure reversal phenomenon especially when testing some older vintages of pipe.

In order to gain the maximum effectiveness from hydrostatic testing and prior to design of such a test, pipeline operators should thoroughly evaluate each pipeline segment and/or pipeline components with respect to potential defect behavior.

5.3.3 HYDROSTATIC TESTING PROGRAMS

A formalized program to pressure test lines already in service should consider:

- a. Age of pipe.
- b. Commodity handled.

- c. Type of pipe (manufacturing process):
 - 1. Lapweld.
 - 2. Pre-1970 ERW (electric resistance welding process).
 - 3. Post-1970 ERW.
 - 4. DSAW (double submerged arc welding process).
 - 5. Seamless.
- d. Known coating problems and cathodic protection history.
- e. Areas traversed:
 - 1. Environmentally sensitive.
 - 2. Population density.
 - 3. State regulations applicability.
 - 4. Watercrossings.
- f. Previous hydrostatic test.
- g. Failure history/failure analyses.
- h. Operating conditions.
- i. Internal inspection surveys.

Following the consideration of the above factors, a prioritized testing schedule can be developed. In general, give first priority to pipelines that have never been subjected to the minimum acceptable hydrostatic test defined above and second priority to those pipelines that may have been tested but their records have been lost. However, the actual prioritizing may be based on the operator's assessment of risk peculiar to the operator's own system. Reference 49 *CFR* 195 Subpart E.

5.3.4 IMPLEMENTATION

The factors developed above should become the basis for establishing a prioritized hydrostatic testing schedule. The unique characteristics and history of each pipeline segment will need to be taken into account; the overall prioritizing criteria must be based on sound engineering analysis. Gaining access to, and disposal of, test water or other test media will need special consideration and permitting. While most test programs would be expected to use water, other media may be considered, such as crude oil and refined products. Use of other media must follow the requirements set forth in 49 *CFR* Part 195.306.

The pipeline operator should consider limiting the lengths of test sections in areas of large elevation differences so that the target test pressure can be achieved without causing damage to the portion of the pipeline at low elevations. It is desirable to subject as much of the pipeline as possible to the highest pressures.

5.3.5 EFFECTS OF HYDROTESTING

The most common causes of failure that may be expected to occur during hydrotesting are:

- a. Corrosion.
- b. Third party damage.
- c. Manufacturing defects.
- d. Operationally induced defects.

Hydrostatic testing may not identify all structural anomalies contained in a pipeline segment. Defects that remain after a test may be subject to enlargement in service. For example, corrosion pits may become larger because corrosion at undiscovered areas of pitting cannot be mitigated. Frequent large pressure fluctuations in service may cause remaining flaws to grow by fatigue crack growth. If a pipeline has had a history of service or test failures from manufacturing defects, a thorough metallurgical examination should be considered during testing or after the line is back in service to assess the cause and the potential for enlargement of such flaws.

5.4 Internal Inspection

5.4.1 GENERAL

Internal inspection of a pipeline for the purpose of detecting possible pipe anomalies is a useful procedure that can be performed without taking the pipeline out of service. Most internal inspection tools are also equipped with supplementary distance-verifying devices such as girth weld detectors and detectors that respond to above-ground signal generators strategically placed at known locations along the pipeline.

Note: Extra care should be taken to accurately record and define above-ground distances to minimize subsequent difficulties in locating anomalies.

Besides the in-line tools described above, there exists another class of inspection devices that can be pulled through a pipeline by means of a winch cable or crawl under their own power. However, the pipeline must be out of service for such an inspection, and the amount of pipeline that these tools can inspect is limited to short distances.

5.4.2 ANOMALY CHARACTERIZATION

In-line tools are used to locate and, to some extent, characterize anomalies in the pipeline that may affect pipeline integrity. The results of an inspection are used to plan and prioritize a repair or replacement program for the detected anomalies that appear to be of a nature or extent that could have a significant affect on pipeline integrity. Such anomalies are usually repaired or removed from the pipeline.

The next level of repair, that may be carried out over several months or a few years, addresses important anomalies that are not severe enough to require a near-term repair or removal. These anomalies usually do not require removal, and they can usually be remedied by repairs to the coating of the pipeline or removal of debris in the bedding or backfill.

The last level of response usually applies to anomalies that are judged to be insignificant. Anomalies that are judged to be insignificant can be left until another in-line inspection is conducted, at which time they can be reevaluated if necessary.

Assurance Of Hazardous Liquid Pipeline System Integrity

Manufacturing, Distribution and Marketing Department

**API RECOMMENDED PRACTICE 1129
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Assurance Of Hazardous Liquid Pipeline System Integrity

SECTION 1—GENERAL

1.1 Scope and Purpose

This recommended practice is a basic guide and information resource for activities to assist in providing increased assurance of a pipeline system's integrity. It covers design and construction considerations; system monitoring and controls; corrosion controls; inspections, reviews and audits; and damage prevention. The purpose of this recommended practice is twofold: to compile a wide base of current industry experience, knowledge, information, and management practices into a cohesive document comprising a range of best practices and to assist pipeline operators in increasing the integrity of their pipeline systems.

The facilities covered by this recommended practice include pipelines and pipeline segments, pumping stations, metering facilities, tankage facilities, and other facilities that may be integral to the operation of a hazardous liquid pipeline.

Information is presented in this recommended practice in the form of recommendations (designated by the use of the word "should") and in the form of mandates (designated by the use of the word "shall"). This recommended practice incorporates by reference a number of other standards, as well as the requirements set forth in 49 *Code of Federal Regulations (CFR)* 195 and other recommended practices. The distinctions in the referenced documents are not changed by the nature of their reference in this recommended practice.

It is the intent that this recommended practice supplement the minimum requirements of DOT 49 *CFR* 195 where applicable and be applied to those facilities outside the scope of these regulations as well.

Some monitoring, reporting, testing, and inspection intervals referenced in 49 *CFR* 195 as establishing requirements may not necessarily be justified on a risk assessment analysis.

1.2 Definitions

1.2.1 bond or continuity bond: A metallic connection that provides electrical continuity.

1.2.2 carrier pipe: A steel pipe for transporting gas or liquids.

1.2.3 cased pipeline or cased pipe: A carrier pipe inside a casing that typically crosses beneath a railroad, roadway, berm, or dike.

1.2.4 casing: A conduit through which the carrier pipe may be placed.

1.2.5 cathodic protection: The prevention or mitigation of corrosion by making the pipeline a cathode by means of an impressed direct current or attachment of a galvanic anode.

1.2.6 certification: Documentation of an individual's qualification.

1.2.7 code: A standard or system of principles or rules developed to meet national industry or regulatory standards which assure the protection of the general public and the environment and which follow sound engineering practices.

1.2.8 commodity: The material being transported through a pipeline.

1.2.9 component: A general term for any item that is part of a pipeline other than straight pipe or field bend.

1.2.10 corrosion: The deterioration of a material, usually a metal, due to a chemical or electrochemical reaction with its environment.

1.2.11 corrosion inhibitor: A chemical compound, either organic or inorganic, which when added to the commodity in the proper concentration, controls or reduces internal corrosion of a pipeline system under most operating conditions.

1.2.12 deadlegs: Components of a piping system that normally have no significant flow under certain operating conditions. Examples include the following: lines with normally closed block valves, spare pump piping, drains, bleeders, instrument connections, stagnant control valve bypass piping and relief valve inlet.

1.2.13 defect: An imperfection of sufficient magnitude to warrant rejection based on the requirements of industry standards.

1.2.14 design pressure: The maximum pressure permitted as determined by the design and testing procedures applicable to the materials and locations involved.

1.2.15 dike liner: A system or device, such as a membrane, installed beneath the storage tank and throughout the containment area, that will contain any accidental release of product from the tank and prevent it from reaching the groundwater.

1.2.16 electrical isolation: The condition of being electrically separated from other metallic structures or the environment.

1.2.17 electrolyte: An ionic conductor usually mixed with water. The electrolyte is normally the soil in pipeline applications.

1.2.18 erosion: Deterioration of the surface occurring as the result of the abrasive action of moving fluids accelerated by the presence of solid particles or gas bubbles in suspension.

1.2.19 foreign structure: Any metallic structure that is not intended as part of the cathodic protection system of interest.

1.2.20 galvanic anode: A metal which, because of its relative position in the galvanic series, provides sacrificial protection to metals that are more noble in the series, when coupled in an electrolyte. These anodes are the source of current in one type of cathodic protection.

1.2.21 half-cell reference electrode: Another name for a reference electrode (normally copper/copper sulfate when used on land).

1.2.22 holiday: A discontinuity of coating that may expose the metal surface to the environment.

1.2.23 integrity: The state of a system which, when operating within its operating parameters or envelope, fulfills the design intent.

1.2.24 in-line tool (instrumented internal inspection device) or smart pig: One of a variety of instrumented tools using one or more physical or electromechanical principles for measuring and recording information (positioning and relative severity) in a pipeline.

1.2.25 interference bond: A metallic connection designed to control cathodic protection current interchange between pipeline components.

1.2.26 interference current or stray current: Current flowing through paths other than the intended circuit.

1.2.27 insulating flange: A flanged joint between adjacent lengths of pipe in which the nuts, bolts, and piping are electrically isolated from one or both of the flanges and the joining gasket is nonconducting so that an electrical barrier exists in the pipeline between the flange set.

1.2.28 job description: A specific definition of pertinent project details such as location, physical dimensions, construction/fabrication requirements and other information needed to fully delineate a particular project or function.

1.2.29 maximum allowable operating pressure (MAOP): The maximum pressure at which a pipeline or segment of a pipeline may be operated, as determined by applicable design codes and/or regulations to the particular pipe specification.

1.2.30 pigging: The operation of transporting a device or combination of devices (scraper, sphere, flexible or rigid materials (foam, plastic, etc.), instrumented tool, etc.) through a pipeline for the purpose of clearing, cleaning, sizing, separation, or anomaly measurement.

1.2.31 pipeline, in-service: A pipeline that is being used for the transportation of fluid.

1.2.32 pipeline, offshore: A pipeline laid under maritime waters and estuaries, below the high water mark.

1.2.33 pipeline, onshore: A pipeline laid on or in land whose surface is above high water mark, including those sections laid under inland waterways.

1.2.34 pipeline operator: The company or other entity which has responsibility for operating and maintaining the pipeline system.

1.2.35 pipe-to-soil potential (see structure-to-electrolyte voltage).

1.2.36 polarized potential: The electrical potential across the structure/electrolyte interface that is the sum of the corrosion potential and the cathodic polarization.

1.2.37 pipeline system: All parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

1.2.38 rectifier: A device for converting alternating current to direct current for cathodic protection purposes.

1.2.39 risk (of failure): The product of the probability of an event occurring and the consequence of the event when it has occurred.

1.2.40 reference electrode: A device whose open circuit potential is constant under similar conditions of measurement.

1.2.41 SCADA: The Supervisory Control and Data Acquisition system to control and monitor pipeline systems.

1.2.42 shielding: The preventing or diverting of the cathodic protection current from its intended path.

1.2.43 shorted pipeline casing: A casing that has a metallic contact with the carrier pipe.

1.2.44 specification: A detailed, precise presentation of requirements for a particular activity or procedure, which may include material composition and properties and dimensional requirements of components.

1.2.45 standard: A document that establishes a system of general principles, specifies dimensions, methods and characteristics, defines terms and gives guidance.

1.2.46 stray current corrosion: Corrosion resulting from direct current flow through paths other than the intended circuit.

1.2.47 structure-to-electrolyte voltage (also structure-to-soil potential or pipe-to-soil potential): The voltage difference between a metallic structure and the electrolyte which is measured with a reference electrode in contact with the electrolyte.

1.2.48 test lead: An electrically conductive wire or cable attached to a structure and leading to a convenient location, used for the measurement of structure-to-electrolyte potentials or current measurements.

1.2.49 test pressure: The pressure specified or applied to the pipeline and its components on completion of manufacture and/or on completion of construction or requalification and reclassification to test for strength and integrity.

1.2.50 test station: A station that is used as a termination point for one or more test leads.

1.3 Referenced Publications

Unless otherwise specified, the most recent editions or revisions of the following standards, codes, and specifications shall, to the extent specified herein, form a part of this standard.

API

Spec 5L	<i>Specification for Line Pipe</i>
Spec 5L1	<i>Recommended Practice for Railroad Transportation of Line Pipe</i>
RP 5L8	<i>Recommended Practice for Inspection of Line Pipe</i>
RP 5LW	<i>Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels</i>
Spec 6D	<i>Specification for Pipeline Valves (Gate, Plug, Ball and Check Valves)</i>
Spec 6H	<i>Specification for End Closures, Connectors and Swivels</i>
Spec 11N	<i>Specification for Lease Automatic Custody Transfer Equipment</i>
RP 500	<i>Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities</i>
Std 541	<i>Form Wound Squirrel Cage Induction Motors—250 HP and Larger</i>
RP 574	<i>Inspection of Piping, Tubing, Valves, and Fittings</i>

Std 598	<i>Valve Inspection and Testing</i>
RP 610	<i>Centrifugal Pumps for Petroleum, Heavy Duty Chemicals, and Gas Industry Services</i>
Std 650	<i>Welded Steel Tanks for Oil Storage</i>
Std 620	<i>Design and Construction of Large, Welded, Low-Pressure Storage Tanks</i>
RP 651	<i>Cathodic Protection of Aboveground Petroleum Storage Tanks</i>
RP 652	<i>Lining of Aboveground Petroleum Storage Tank Bottoms</i>
Std 653	<i>Tank Inspection, Repair, Alteration, and Reconstruction</i>
RP 1102	<i>Steel Pipelines Crossing Railroads and Highways</i>
Std 1104	<i>Welding of Pipelines and Related Facilities</i>
RP 1107	<i>Pipeline Maintenance Welding Practices</i>
RP 1109	<i>Marking Liquid Petroleum Pipeline Facilities</i>
RP 1110	<i>Pressure Testing Liquid Pipelines</i>
RP 1111	<i>Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines</i>
RP 1113	<i>Developing a Pipeline Supervisory Control Center</i>
RP 1114	<i>Design of Solution-mined Underground Storage Facilities</i>
RP 1115	<i>Operation of Solution-mined Underground Storage Facilities</i>
RP 1117	<i>Lowering In-service Pipelines</i>
RP 1119	<i>Training and Qualification of Liquid Pipeline Operators</i>
RP 1123	<i>Development of Public Awareness Programs by Hazardous Liquid Pipeline Operators</i>
RP 1130	<i>Computational Pipeline Monitoring</i>
Std 2510	<i>Design and Construction of LPG Installations</i>
Std 2610	<i>Design, Construction, Operation, Maintenance and Inspection of Terminal and Tank Facilities</i>
ACI International ¹	
318	<i>Building Code Requirements for Reinforced Concrete</i>
ASME ²	
B31	<i>Code for Pressure Piping</i>
B31G	<i>Manual for Determining the Remaining Strength of Corroded Pipelines</i>

¹ American Concrete Institute, 22400 West Seven Mile Road, P.O. Box 19150, Detroit, MI 48219.

B31.4	<i>Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols</i>	RP0490	<i>Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coatings of 10 to 30 mils (0.25 to 0.76 mm)</i>
B31.11	<i>Slurry Transportation Piping Systems</i>	RP0274	<i>High-Voltage Electrical Inspection of Pipeline Coatings Prior to Installation</i>
	<i>Metals Handbook, Volume 13: "Corrosion"</i>		
AWWA ¹		NAPCA ⁶	
ANSI/AWWA Standard C214	<i>Tape Coatings Systems for the Exterior of Steel Water Pipelines</i>	Bull 1-65-1	<i>NAPCA Specification—Designations for Coal Tar Enamel Coatings</i>
ANSI/AWWA Standard C215	<i>Extruded Polyolefin Coatings for the Exterior of Steel Water Pipelines</i>	NFPA ⁷	
DOT ⁴		30	<i>Flammable and Combustible Liquids Code</i>
49 CFR 40	<i>Procedures for Transportation Workplace Drug and Alcohol Testing Programs</i>	30A	<i>Automobile and Marine Service Station Code</i>
49 CFR 190	<i>Pipeline Safety Program Procedures</i>	70	<i>National Building Code</i>
49 CFR 194	<i>National Preparedness Guidelines</i>	SSPC ⁸	
49 CFR 195	<i>DOT Regulations for Transportation of Liquids by Pipeline</i>	SSPC-SP1	<i>Solvent Cleaning</i>
49 CFR 199	<i>Drug and Alcohol Testing</i>		
NACE International ⁵		1.4 Abbreviations and Acronyms	
RP0572	<i>Design, Installation, Operation, and Maintenance of Impressed Current Deep Ground Beds</i>	ACI	American Concrete Institute
RP0175	<i>Control of Internal Corrosion in Steel Pipelines and Piping Systems</i>	AISC	American Institute for Steel Construction
RP0675	<i>Control of External Corrosion on Off-shore Steel Pipelines</i>	ANSI	American National Standards Institute
RP0286	<i>The Electrical Isolation of Cathodically Protected Pipelines</i>	API	American Petroleum Institute
RP0188	<i>Discontinuity (Holiday) Testing of Protective Coatings</i>	ASCE	American Society of Civil Engineers
RP0169	<i>Control of External Corrosion on Underground or Submerged Metallic Piping Systems</i>	ASME	American Society of Mechanical Engineers
10A192	<i>State-of-the-Art Report on Steel Cased Pipeline Practices</i>	AWWA	American Water Works Association
		CFR	<i>Code of Federal Regulations</i>
		CIS	Close Internal Survey
		DOT	U.S. Department of Transportation
		EPA	U.S. Environmental Protection Agency
		MIC	Microbiological Influenced Corrosion
		NACE	National Association of Corrosion Engineers
		NDE	Non-Destructive Examination
		RP	Recommended Practice
		ROW	Right-of-Way
		SCADA	Supervisory Control and Data Acquisition
		Spec	API Specification
		SSPC	Steel Structures Painting Council
		Std	API Standard
		UL	Underwriters Laboratories
		USCG	United States Coast Guard

² American Society of Mechanical Engineers, East 47th Street, New York, NY 10017.

³ American Water Works Association, 6666 West Quincy Ave., Denver, CO 80235.

⁴ U.S. Department of Transportation, available from the U.S. Government Printing Office, Washington, D.C. 20402.

⁵ NACE International, 1440 South Creek Drive, P.O. Box 218340, Houston, TX 77218-8340.

⁶ National Association of Pipe Coating Applicators, 333 Texas St. Suite 800, Shreveport, LA 71101-3673.

⁷ National Fire Protection Association, 1 Batterymarch Park, Quincy, MA 02269.

⁸ Steel Structures Painting Council, 40 24th Street, Suite 600, Pittsburgh, PA 15222.

SECTION 2—DESIGN AND CONSTRUCTION CONSIDERATION FOR INTEGRITY ASSURANCE

2.1 General

Assurance of pipeline integrity for new pipeline systems and for in-service pipelines modified for reasons of relocation, expansion, upgrading or other significant system revision begins with design and construction practices. These practices, developed and refined over the history of pipelining and improved through new technology and experience, include industry standards and recommended practices, codes, specifications, quality construction, inspection and documentation aspects.

Likewise, DOT 49 *CFR* 195, Subpart C: "Design Requirements" and Subpart D: "Construction" identify minimum pipeline standards and require adherence to many of these accepted industry practices.

Note: Edition of the API documents listed below may not be incorporated by reference in 49 *CFR* 195. In addition, state and local codes may apply.

API has developed industry standards and recommended practices that cover design and construction of pipelines, stations, terminals and tanks, and storage facilities, as indicated below and as shown in the reference section of this document:

2.1.1 PIPELINES, STATIONS AND APPURTENANCES

- a. API Spec 5L.
- b. API Spec 5L1.
- c. API RP 5L8.
- d. API RP 5LW.
- e. API Spec 6D.
- f. API Spec 6H.
- g. API Spec 11N.
- h. API RP 500.
- i. API RP 1102.
- j. API Std 1104.
- k. API RP 1107.
- l. API RP 1109.
- m. API RP 1110.
- n. API RP 1111.
- o. API RP 1113.
- p. API RP 1114.
- q. API RP 1117.
- r. API RP 1123.
- s. API RP 1130.
- t. *API Manual of Petroleum Measurement Standards*
- u. Numerous API materials specifications.

2.1.2 TANKS, TERMINALS AND OTHER STORAGE FACILITIES

- a. API STD 620.
- b. API STD 650.
- c. API RP 651.
- d. API RP 652.
- e. API STD 653.
- f. API RP 1130.
- g. API RP 1114.
- h. API STD 2610.

The requirements in these documents and practices should be followed, but where applicable codes and regulations are more stringent, such codes and regulations shall be adhered to and will supersede the aforementioned standards and practices.

Compliance with this section will assist in assuring initial integrity requirements are met for onshore and offshore pipeline systems.

2.2 Codes

2.2.1 GENERAL

The first consideration to help assure pipeline integrity involves using design and construction codes to set forth engineering requirements. Then the application of time tested operational practices and the uniform application of sound engineering principles, will more readily assure the safety and integrity of a pipeline and its component parts.

Codes outline requirements for:

- a. Basic design.
- b. Material quality/selection criteria.
- c. Workmanship.
- d. Construction/fabrication parameters.
- e. Inspection.
- f. Quality assurance testing.

Initially, the usage of the term "code" meant a system of principles or rules, which were to be followed accordingly by the industry. Due to various legislative and regulatory efforts, many industry standards and specifications took on the force of codes.

2.2.2 PIPELINE CODES

Industry codes applying to pipelines and that should be followed include, but are not limited to the following:

- a. ASME B31.4.

- b. ASME B31.11.
- c. NFPA 30.
- d. NFPA 30A.
- e. NFPA 70.

Note: Certain documents are incorporated by reference into 49 *CFR* 195. When only a portion of a document is referenced, then only that portion is considered to require compliance under 49 *CFR* 195 and the remainder of the document is not subject to 49 *CFR* 195 compliance.

The standards and specifications, along with other applicable recommended practices should be followed in designing and constructing pipelines and their associated components.

2.2.3 REVIEW PROCESS

A formal review process to assure pipeline system designs meet requirements should be instituted. Validation of design requirements should be carried out by an appropriate number of qualified engineering/operations management personnel such as:

- a. Project engineer.
- b. Design review team.
- c. Project manager/supervisor.
- d. Engineering manager.
- e. Professional engineer.
- f. Operating manager.
- g. Field operations representative.
- h. Consultant.

2.2.4 ADDITIONAL REQUIREMENTS.

Written policies and/or guidelines developed by contractors or pipeline operating companies delineating either specific interpretations or additional design requirements may be developed to more adequately address such areas as:

- a. Safety and environmental.
- b. Welding.
- c. Pipe, fittings, valves.
- d. Coatings.
- e. Tanks.
- f. Major equipment (prime movers, etc.).
- g. Station design.
- h. Pipeline appurtenances.
- i. Construction techniques and inspection.
- j. Testing procedures/criteria.
- k. Design factors for areas requiring more stringent treatment or additional attention, for example, populated or environmentally sensitive areas.
- l. SCADA.
- m. Specific state and local requirements.
- n. Other specific company engineering standards.

2.3 Specifications

2.3.1 GENERAL

Development and utilization of specifications should be used to provide detailed requirements, including material composition, physical characteristics (toughness, weldability, etc.) and dimensional requirements, for the following:

- a. Pipe, pipe components and fabrications.
- b. Lighting and electrical components.
- c. Buildings and foundations.
- d. Valves.
- e. Corrosion control systems (See Section 4).
- f. Pump station equipment.
- g. Connections.
- h. Pipeline construction.
- i. Station construction.
- j. Terminal/tankage construction.
- k. Other installations/equipment/appurtenances.
- l. Highway, railroad, water crossings.
- m. Communications and supervisory controls.

Specifications may include in-house, industry or manufacturing specifications and/or instructions. For example, API Specs 5L (pipe) and 6D (valves) provide a basis for these requirements.

2.3.2 GENERAL SPECIFICATIONS

General specifications are often used to provide additional details, guidance or instruction to assure quality and integrity. 49 *CFR* Part 195.202 requires construction in accordance with a comprehensive set of written specifications or standards. Additional details may include such areas as environmental measures, company/contractor relationships/expectations, permitting, subcontractors, schedules, job progress and construction safety requirements. General specifications should, at a minimum, cover the following areas as outlined in paragraphs 2.3.2.1 through 2.3.2.5.

2.3.2.1 General Requirements

Specifications in conjunction with agreements/contracts between constructor/installer and company/owner, job descriptions for specific project delineation and drawings comprise the complete package which establishes the following:

- a. Safety and environmental considerations.
- b. Materials quality (weldability, toughness, etc.).
- c. Workmanship.
- d. Construction/fabrication quality.
- e. Quality assurance measures.
- f. Documentation requirements.

2.3.2.2 Pipeline Construction

- a. Alignment and survey.
- b. Preparation/use of ROW.
- c. Unloading/handling/stringing.
- d. Trenching requirements.
- e. Bending/alignment.
- f. Welding.
- g. Coatings.
- h. Lowering/backfill/cleanup.
- i. Line cleaning/sizing/dehydrating.
- j. Special construction requirements—waterway, swamp, populated areas, road, and railroad
- k. Crossings.
- l. Spans.
- m. Inspection and testing.
- n. Signs and markings.

2.3.2.3 Station and Terminal Construction

- a. Layout/survey/siting.
- b. Site preparation/earthwork/fencing.
- c. Concrete work.
- d. Equipment installation.
- e. Piping and welding.
- f. Electrical/instrumentation work.
- g. Coating and painting.
- h. Backfill/cleanup.
- i. Inspection and testing.

2.3.2.4 Tank Construction

- a. Layout/survey.
- b. Site preparation/earthwork/fencing.
- c. Geotechnical design.
- d. Foundations.
- e. Bottom preparation.
- f. Layout.
- g. Erection.
- h. Fabrication/welding.
- i. Piping.
- j. Release prevention systems/barriers.
- k. Appurtenances.
- l. Inspection and testing.
- m. Cleaning and painting/coating.
- n. Electrical/instrumentation work.
- o. Tank mixers.

2.3.2.5 Other System Construction Requirements

Specifications should also be used for the following:

- a. Instrumentation.
- b. SCADA systems.
- c. Measurement equipment.

- d. Repair sleeves.
- e. Cathodic protection.
- f. Commissioning.
- g. Component fabrication/buildings and other structures.
- h. Pretesting, purging, and/or other acceptance criteria.

Proper development and use of this entire package should provide initial pipeline safety and integrity assurance and meet the requirements of 49 *CFR* Parts 195.200–195.366 (Subpart D).

2.4 Pipeline Route Selection and Environmental Protection

ASME B31.4 and 49 *CFR* 195.210, establish proximity and pipeline cover requirements. State and local governments can apply their land use authority to affect the routing of pipelines that cross their jurisdictions. These requirements may be more stringent than federal codes and should be investigated. Pipeline routing should be based on a formalized risk assessment/management technique.

Generally, the routing of a new pipeline is developed through a review of the following critical factors:

- a. Availability of land rights.
- b. Difficulty of terrain, obstructions and earth conditions.
- c. Proximity to different types and uses of developed land, including expectations about future development and zoning.
- d. Proximity to environmentally sensitive areas.

Pipeline operators should work through appropriate local agencies or through independent research and analysis to determine if a pipeline path crosses areas considered to be sensitive. The local permitting process may require a review of such sites.

Depending on the characteristics of the construction project, additional measures may be necessary such as:

- a. Modified design and construction specifications which may include added mechanical strength or protection such as:
 - 1. Heavier wall pipe.
 - 2. Various forms of external pipe protection such as protection pads, concrete coating, etc.
 - 3. Increasing the depth of the pipe.
 - 4. Increased number of flow restricting devices (valves).
 - 5. Use of remotely controlled flow restriction devices.
- b. Modified operating, maintenance or inspection procedures may include:
 - 1. Adjustment in operating pressure.
 - 2. Increased line marking practices.
 - 3. Increased surveillance frequency.
 - 4. Increased maintenance inspections.
 - 5. Increased cathodic protection testing.
 - 6. Use of remotely controlled flow restriction devices.

2.4.1 RIGHT-OF-WAY CONSIDERATIONS

Pipeline designs should ensure that a minimum clearance and work space requirement is established which is appropriate for the size of line and the construction, operating, and maintenance conditions expected.

The width of the right-of-way (ROW) and/or work space should accommodate the construction and maintenance equipment, a ditch with appropriate sloping or shoring, excavated soils and any other specific needs anticipated during construction or routine maintenance. Adequate ROW is essential during the construction phase, but becomes critical for pipeline maintenance and possible emergency response later in the life of the system.

Easements that allow a specified permanent corridor as well as additional work space necessary during construction, and emergency response situations work well. Where possible, ROW agreements should also include the ability to install facilities to access valves or other appurtenances along the pipeline. Consideration should be given to the land use when formulating the terms of a ROW agreement including additional line rights. Where a higher risk activity is or may be present along the ROW, the pipeline operator should take action through the terms of the ROW agreement. Where agricultural activity is a consideration, for example, the ROW agreement can specifically limit agricultural activity in the immediate area of the pipeline.

In addition to the terms of the ROW agreement, the pipeline operator can minimize the risk of external damage by modifying pipeline design and construction specifications and/or modified operating, maintenance, or inspection procedures. For example, where agricultural activity is a consideration, the pipeline may be installed at greater depths, marked at closer intervals, etc.

Efforts should be made to work closely and cooperatively with landowners and the communities affected by the pipeline construction. Special consideration should be given to appropriately restoring the ROW after maintenance and construction activities. Establishing good relationships through positive landowner relations can be beneficial in the long-term maintenance and protection of the pipeline.

2.5 Construction Contractor/Supplier Considerations

Beyond the specific requirements for design, material selection, construction/installation specifications and inspection/testing criteria, an evaluation should be carried out to assure quality and capability prior to selection and engagement of construction contractor(s), material equipment suppliers, and other resources. Thorough screening and

evaluation should qualify these resources so they are consistent with all other components of pipeline installation.

Areas which should be included in this evaluation are:

- a. Work record/experience.
- b. Workmanship/quality factors.
- c. Financial stability.
- d. Organizational capabilities—management, structure, support staff, etc.
- e. Personnel capabilities—experience/training/skills.
- f. Safety record.
- g. Training programs.
- h. Drug/alcohol program.
- i. Equipment/other resource capability.

Utilization and evaluation of the above considerations should be applied to pipeline and station contractors, component manufacturing/fabrication/building/assembly, maintenance functions and other installation and erection activities.

2.6 Inspection

Pipeline operators have a long tradition of inspecting the design, materials and components, fabrication, assembly and particularly construction of a pipeline system. The reason for comprehensive inspections is to assure the highest degree of reliability possible. Reliability is important because many pipeline facilities are far from the location of operations personnel.

Furthermore 49 *CFR* 195.204 requires inspection to ensure pipeline systems are installed in accordance with certain requirements and procedures. Regulations require that inspections be performed by trained and qualified personnel.

2.6.1 PURPOSE OF INSPECTIONS

The primary purpose of inspections is to assure adherence to codes and accepted practices, specifications, project descriptions, contractual provisions, drawings, and specific company policies and procedures. In its simplest form, it is a quality assurance function. More broadly, it should also include responsibilities for monitoring and ensuring items such as:

- a. Safety.
- b. Public relations.
- c. Progress and coordination.
- d. Vendor and contractor relations.

2.6.2 TYPES OF INSPECTION AND SUGGESTED REFERENCE CODES

Inspection of the following activities should be provided to further assure adequate integrity levels:

2.6.2.1 Fabrication-shop/pipe mill/manufacturing facility

Type of Inspection	Reference Code
Pipe manufacturing	API Spec 5L, RP 5L1, RP 5L8 and RP 5LW
Pipe coating, plant applied	NACE International RP 0169, RP 0175, RP 0188, RP 0274 and RP 0675 AWWA C214 and C215 SSPC (surface prep)
Bend manufacturing	ASME B31.4
Pipe fabrication/assembly/testing	ASME B31.4
Driver calibration/testing	API Std 541
Pump calibration/testing	API Std 610
Switchgear calibration/ testing	API RP 500 NFPA 70
Valves	API Std 598, API Spec 6D API Spec 6D, API Spec 6H, API RP 574, ASME B31.4
Other critical components/appurte- nances—manufacturing, fabricat- ing or assembling	

2.6.2.2 Pipeline Construction

Type of Inspection	Reference Code
Alignment and surveys	ASME B31.4
ROW clearing, unloading/hauling/ stringing	ASME B31.4
Trenching	ASME B31.4
Bending/pipe alignment	ASME B31.4
Welding	ASME B31.4 API Std 1104
Coating(s)	NACE International RP0188, RP0274 and RP0490 NAPCA Bulletins ASME B31.4
Lowering/backfill/cleanup	—
Line cleaning/sizing/dehydrating (if required)	—
Special construction requirements:	
1. Sensitive areas	ASME B31.4
2. Crossings	API RP 1102
3. Offshore	ASME B31.4 API RP 1111
Spans	ASME B31.4
Hydrostatic testing	API RP 1110 ASME B31.4

Type of InspectionOther associated activities, such as
pipeline marking, valve installations,
and protective barriers.

Cathodic protection

Construction documentation

Reference CodeAPI RP 1109
ASME B31.4NACE International
RP 0169,
RP 0572,
RP 0675

ASME B31.4

2.6.2.3 Station/Terminal Construction

Type of Inspection	Reference Code
Station/terminal construction	API Std 2510 API Std 2610
Layout/survey	—
Site preparation	—
Concrete work	ACI 318
Building construction	ASME B31.4, local building codes
Equipment installation	ASME B31.4
Electrical/instrumentation work	API RP 500, NFPA 70
Coating, painting and cathodic protection	NACE International RP 0572 NAPCA Bulletins SSPC (surface prep)
Backfill/cleanup	ASME B31.4
Piping and welding	API Std 1104 ASME B31.4
Other associated activities such as: security, marking and signage, fenc- ing, etc.	API RP 1109 ASME B31.4
Testing and checkout	API RP 1110 ASME B31.4
Commissioning	ASME B31.4
Construction documentation	ASME B31.4

2.6.2.4 Tank Construction

Type of Inspection	Reference Code
Tank construction	API Std 650 API Std 2510 API Std 2610 NFPA 30
Layout, spacing and survey	—
Site preparation	—
Geotechnical design/cathodic protection	API RP 651 RP 652
Foundations	—
Erection	API Std 650
Cathodic protection	RP 0193
Welding/fabrication	API Std 650 API RP 653

Type of Inspection	Reference Code
Release prevention/containment systems/barriers	ASME B31.4
Piping/appurtenance installation	API RP 653
Coating/painting application	SSPC Publications NACE International RP's
Electrical work	API RP 500
Testing	API RP 653
Cleanup	—
Construction documentation	ASME B31.4

2.6.2.5 Other Installations

Other installations should be inspected in the same manner and for the same reasons as pipeline, stations/terminals, and tank construction. These installations would include:

Type of Inspection	Reference Code
Measurement facilities	API Manual of Petroleum Measurement Standards and API Spec 11N
Provers-installation/calibration	API Manual of Petroleum Measurement Standards and ASME B31.4
SCADA systems	API RP 1113
Instrument/electrical modifications	API RP 500 NFPA 70
Platform/marine facilities	ASME B31.4
Underground storage (caverns)	API RP 1114
Maintenance related projects: line replacements/relocations/lowering	API RP 1117
Line repairing	API RP 1107
Abandonments, purging, and/or takeup	ASME B31.4
Hydrostatic tests	API RP 1110
Internal inspections	ASME B31.4
Cathodic protection/installations rectifiers/anode beds	NACE International RP's
Stopple/hot tapping operations	ASME B31.4
ROW clearing and/or side trimming.	—

2.6.2.6 Other Services

Other services listed below should be employed as necessary to further assure thorough inspection. These include:

- X-ray inspection of welding.
- Ultrasonic inspections.
- Magnetic flux leakage inspections (pipelines and tanks).

- Infrared inspections.
- Inspector qualifications and training.

All personnel engaged in inspection activities, whether company employees or third parties, shall be properly trained and qualified in the phase of construction to be inspected.

- Training: Inspectors should have successfully completed applicable training courses or possess sufficient practical experience to perform assigned inspection duties. Inspectors may also be certified for positions, such as:
 - Welding inspectors.
 - NDE inspectors.
 - Manufacturer inspection (certification by manufacturer).
 - Hydrotest inspectors.
 - Tank inspectors (API Standard 650 and 653).
 - Corrosion control and coating inspectors.

- Recertification should be required on a periodic basis that is acceptable for the type of inspection to be performed. Inspector training and qualification is based on the phase of construction to be inspected.
- Documentation of applicable training, qualifications and certifications should be current, maintained, and readily retrievable.

2.7 Records and Documentation

A complete record of pertinent construction data should be maintained to ensure that throughout the operating life of the pipeline, adequate information exists to assess its maintenance needs and operational integrity. While recommendations listed below for records and documentation pertain to new pipeline and related facility construction, existing in-service facilities records should follow similar document requirements.

Specifically, 49 CFR 195.266 requires that information must be maintained for the pipeline facility on the following:

- Total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld.
- Amount, location and cover of each size of pipe installed.
- Location of each crossing of another pipeline.
- Location of each buried utility crossing.
- Location of each overhead crossing.
- Location of each valve and corrosion test station.

In addition to those requirements outlined above, pipeline operators may consider retaining additional pertinent records and documentation that might be useful in evaluating the operating condition of a pipeline or pipeline system. These include the following:

- Mill certificates for the pipe used in the construction.
- Land survey records.
- Corrosion control facilities records.

- d. Coating material.
- e. Application information.
- f. Hydrostatic test records.

- g. Welder qualification records.
- h. Inspector qualifications.
- i. Construction drawings.

SECTION 3—SYSTEM MONITORING AND CONTROL

3.1 General

Pipeline companies use specific operating and design practices as well as control and monitoring systems to ensure the pipeline system integrity. Controls provided to adjust the pipeline system operations may act locally or remotely and with either automatic or manual mode(s). Most pipeline systems are remotely monitored and controlled through the Supervisory Control and Data Acquisition (SCADA) system. The SCADA system allows personnel in the control center to continuously observe the pipeline system operation and ensure its integrity from operating parameters (such as pressure or flow). The pipeline controller must be able to operate the pipeline system within acceptable limits during normal and abnormal conditions.

3.2 Controls

Knowledge of valves, actuators, pressure control devices, communication systems, and SCADA systems is required for the design of controls for safe operation of a pipeline system. A thorough understanding of the physical characteristics of the specific pipeline system is required for proper application of control equipment.

3.2.1 EMERGENCY FLOW RESTRICTING DEVICES

Emergency Flow Restricting Devices (EFRDs), which on liquid pipelines are check and block valves, may be used on line segments to limit a release. The check valve acts as a one-way flow device and automatically prevents the backward flow into lower elevations. The block valve can be operated either locally or remotely to prevent flow in the pipeline after pumping has been stopped. There are a variety of valve types which can be used for these functions. Effective use of EFRDs depends on the proper design, location, and prompt action by the pipeline controller or control system to minimize the pipeline drain-down.

The type and location of valves along a pipeline should be based on engineering analysis. The analysis should take into account such variables as:

- a. Populated areas.
- b. Environmental concerns.
- c. Navigable waterways.
- d. Linefill/volumes between valves.
- e. Topographic conditions.

- f. Hydraulic considerations.
- g. Material being transported.
- h. Seismic concerns.
- i. Accessibility.
- j. Access to power and communication.
- k. Security.
- l. Valve access.

The type of valve actuation method selected by the designer should be coordinated with the requirements imposed for closure, fluid in pipeline, compatibility with technology currently used, availability of energy sources, and maintenance requirements. There are a variety of valve actuation methods that may be employed depending on the application. These actuation methods may include:

- a. Manual.
- b. Hydraulic.
- c. Electrical.
- d. Electro-hydraulic.
- e. Pneumatic.
- f. Drop check.

Note: Quick closing valves may cause hydraulic conditions that could ultimately result in over-pressure.

There are three primary control modes for power-operated valves:

- a. Operated by local manual or powered controls.
- b. Remote controls.
- c. Automatic controls.

The control mode selected for operation of power-actuated valves should be coordinated with the overall response plans and hydraulic characteristics of the pipeline system. Important measures for minimizing a product release are: (a) proper sequencing of pump station shutdowns, (b) linefills/volumes between valves, and (c) topographic conditions. In general, the use of automatic, power-operated EFRD valves is not recommended on liquid pipelines because of pressure surges that will occur in the case of sudden and/or uncommanded closure. If the pipeline operator feels that an automatic EFRD is warranted, the pipeline operator shall conduct a thorough analysis of the use of such valves. If automatic EFRD valves are installed the operator shall provide protection against uncommanded closures and/or protection against excessive surge pressure.

In some scenarios it may be more appropriate to leave valves open to allow product to drain away from release sites to reduce overall hazards or release impact.

3.2.2 PRESSURE SAFETY DEVICES

Pressure safety devices can be used to limit pressure and to determine when abnormal operating conditions exist. Determining the particular condition depends on the operation of the pipeline system and coordination with the pipeline system control philosophy. Some examples of the type of conditions which can be sensed are:

- a. Low pressure.
- b. High pressure.
- c. Low flow.
- d. High flow.
- e. Reverse flow.
- f. Pig passage.
- g. High tank level.

The design of a pipeline should provide adequate controls to ensure that the pipeline pressure is maintained at levels less than or equal to the maximum operating pressure (MOP) established for the line segment. ASME B31.4 and 49 CFR 195.406(b) require pressure controls which are adequate to ensure that when abnormal conditions occur, the pressure will not exceed 110 percent of MOP. To maintain the pipeline pressures within these safe operating parameters, pressure safety devices may be required. The types of devices that may be applied include:

- a. Control valves.
- b. Variable speed drivers.
- c. Electronic pressure transmitters.
- d. Pressure switches.
- e. Relief devices.
- f. Pressure regulators.
- g. Smart controllers.

3.2.3 DEVICES FOR MONITORING OTHER OPERATING PARAMETERS

In addition to pressure there are other pipeline operating parameters which should be monitored by the pipeline controller to provide an overview of the pipelines status. These may include:

- a. Temperature.
- b. Flow rate.
- c. Product characteristics.
- d. Valve position.
- e. Equipment status.
- f. Metered volume.
- g. Line balance.
- h. Tank levels.
- i. Alarm status.

Switches, and other instrument signals are transmitted to the key elements of the SCADA system.

3.2.4 SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEMS

The SCADA systems used for monitoring liquid petroleum pipelines should be designed for rapid response, real-time data gathering, alarm annunciation, reporting, and data retention.

The SCADA systems may be used to initiate sequenced control or drive individual field devices to predetermined points.

The configuration of a SCADA system should be designed to be compatible with normal operation of the pipeline system and should provide alarms for abnormal conditions.

The operation of a SCADA system is dependent upon the quality of the data which is received from field locations. Therefore, the calibration of field instrumentation should be given a high priority with the calibration performed on a routine basis by qualified technicians.

The integrity of the SCADA system may be improved by including a back-up for the main system. This would allow for continued control in the event of a malfunction in the primary system or if off-line maintenance is required. The use of a separate geographic site for a secondary system should be considered during the development of the SCADA system to reduce the risk of long term outages during natural disasters or other unforeseen outages.

3.2.5 COMMUNICATION SYSTEMS

Pipeline systems operated with a SCADA system require a method of transmitting data. There are a variety of communication modes that can be applied. These include:

- a. Microwave.
- b. Satellite.
- c. Fiber optic.
- d. Radio links.
- e. Telephone (wire/cellular).
- f. Conventional dial phone lines.
- g. Dedicated phone lines.

The designer should consider how loss of communication would affect the integrity of the control system. To maintain the SCADA system integrity, it may be desirable to ensure the availability of an alternate communication mode.

3.3 Leak Detection

Pipeline companies use a number of procedures and methods to detect the movement of products in their pipelines. These methods may include:

- a. Computational pipeline monitoring (CPM).
- b. Station sensors.
- c. Monitoring of line conditions by pipeline controllers.
- d. Deviation of measured values (pressure, flow) beyond established norms.

3.3.1 COMPUTATIONAL PIPELINE MONITORING

CPM methods have been developed as tools in detecting product releases. These monitoring methods vary widely in their use of software from complex integrated models to direct data comparison. They also use a variety of means to sense key parameters from pressure transmitters, level sensors and various volumetric measuring devices such as positive displacement or turbine meters, and ultrasonic flow meters. Most monitoring methods use an existing SCADA system for data collection and display, while some are adaptable to smaller applications not having the benefit of a SCADA system. These applications usually provide an alarm to the pipeline controllers so an investigation and response can be initiated.

3.3.2 STATION/TERMINAL SENSORS

Sensors at pump stations or other selected locations are installed to prevent or detect product release. These may include:

- a. Gas sensors used to detect the presence of combustible vapors.
- b. Hydrocarbon sensing cables/devices.
- c. Flow measuring seal failure switches, pressure switches, level sensors, and other detection devices.

3.3.3 MONITORING OF LINE CONDITIONS BY PIPELINE CONTROLLERS

Pipeline controllers use SCADA systems that display information from the pipeline and allow them to control the operation of the line. With this field data, the pipeline controllers are provided with information that should allow them to detect anomalies in pressure, flow, or other scanned parameters. A pipeline controller can determine if changes in conditions are the result of normal operations or of a pipeline failure. For other changes the pipeline controller may use trending parameters. Over/short volume balance calculation to assess line conditions and/or various types of volumetric readings could indicate a trend in fluid loss.

Maintaining pressure on shutdown/isolated pipelines is sometimes used by pipeline controllers to check for integrity. The pressure is maintained at a set value and any unexplained drop in pressure may indicate a product release.

3.4 Training/Testing

3.4.1 GENERAL

Pipeline operators should establish stringent and clear training standards for design and operational safety to maintain a viable business enterprise. Minimum requirements are detailed in 49 *CFR* 195. Regulations are augmented by function-specific industry standards that also set minimum levels

of design and procedure. Refer to API RP 1119 for information regarding training for pipeline control personnel.

3.4.2 TYPES OF TRAINING

The types of training approaches available to meet training needs include: (a) PC-based self study, (b) formalized classroom training, (c) interactive video, and (d) on-the-job training. There are a number of packaged training programs available that are directed at pipeline operations; or, packages tailored for a specific company can be developed. Most programs use a combination of the various approaches.

3.4.3 VALIDATION OF TRAINING

Validation of the effectiveness of training could be through any combination of: (a) written, (b) hands-on, (c) computer, or (d) oral methods appropriate for the function tested. For some functions, a suitable test might consist of observing hands-on performance supplemented by appropriate questioning.

When a computer-based simulator is available, some companies provide their pipeline controllers the opportunity to test their skills for both normal and abnormal operating conditions without jeopardizing the integrity of the actual pipeline system. To ensure that pipeline controllers are remaining up-to-date on the operation of their respective pipeline system, a continuing review program should be incorporated. This continuing review could be accomplished through observation by the supervisor during normal duties or through off-line training and testing.

3.4.4 SUBSTANCE ABUSE TESTING PROGRAMS

Operators of pipelines subject to 49 *CFR* 195 are mandated to maintain a workplace drug and alcohol testing program as described in 49 *CFR* 199 and 49 *CFR* 40. These rules require drug and alcohol abuse prevention education and training for supervisors and employees (along with various types of testing). Employees should receive general training on drug and alcohol use. Supervisors' training must include training on physical, behavioral, and performance indicators/detection of drug and alcohol use.

3.4.5 MANUALS AND TRAINING

Manuals mandated by 49 *CFR* Part 195.402 are required to include procedures that cover maintenance and normal operations, methods to ensure safety when operating design limits have been exceeded, response to emergency conditions, and how to recognize conditions that could lead to safety related conditions. These manuals must be reviewed once each calendar year at intervals not to exceed 15 months. 49 *CFR* Part 195.403 requires operators to establish and conduct training programs for operations and maintenance personnel so these personnel can perform the duties for which they are responsible.

3.4.6 OPERATING RECORDS

When event loggers are used as part of the SCADA system the records of all pipeline controller actions are available as a training tool. These records can be reviewed by management personnel, and the findings can be incorporated into regular refresher training.

3.4.7 EMERGENCY RESPONSE TRAINING

Emergency response drills, provide an opportunity for pipeline personnel to place the procedures incorporated in emergency response plans into action in a controlled setting. These drills shall be comprised of actual field exercises and table top exercises. In some cases the drill involves public emergency response units to assist in liaison with these agen-

cies. Post drill reviews are used to improve the overall emergency response plan. This training improves the cooperation between the agencies and pipeline operators and raises the awareness of all parties. 49 *CFR* 194 (OPA '90) (see Section 1.3) establishes minimum requirements for such emergency response drills.

3.4.8 OTHER TRAINING

Other training and certification for pipeline personnel is required under Occupational Safety and Health Administration (OSHA) and Environmental Protection Agency (EPA) regulations and industry standards. These requirements can be met by a variety of in-house and contract certification programs.

SECTION 4—CORROSION CONTROL

4.1 Corrosion Control Design of New Pipelines

4.1.1 GENERAL

All newly constructed pipelines should incorporate corrosion control systems within one year of completion of the pipeline (see DOT 49 *CFR* 195.242). Pipelines subject to 49 *CFR* 195 have specific requirements for cathodic protection.

For information on the design of cathodic protection of pipelines refer to NACE International RP 0169 Section 7. DOT 49 *CFR* 195.242 also establishes minimum requirements.

4.1.2 MONITORING

To monitor the effectiveness of the cathodic protection system, test stations for the measurement of potential, current, or resistance should be installed during construction. Recommended locations for test stations include: cased pipe installations, metallic foreign pipeline crossings, insulating joints, banks of river crossings, valve stations, galvanic anode installations, road crossings, stray current areas, and rectifier installations. Refer to NACE International RP 0169 Section 4.5 for more information.

4.1.3 ISOLATION FACTORS

Electrical isolation is to be installed where required to facilitate the application of cathodic protection current. Typically, electrical isolation is installed at: meter stations, well heads, mainline pipe connections, in-line measuring meters, pressure regulating stations, the suction and discharge sides of pumping stations, motorized valves, and other electrical devices connected to the pipeline, and at changes in coating quality. Refer to NACE International RP 0169 Section 4.3, and RP 0286 for more information.

If nonwelded fittings are installed in the piping system, electrical continuity for adequate cathodic protection may require the installation of bonds across the non-welded fitting.

Whenever possible, the use of cased pipe should be avoided. Refer to API RP 1102 and NACE International 10A192.

Pipeline fittings, valves, and bends shall be designed and constructed to accommodate the passage of internal inspection devices to meet DOT requirements (49 *CFR* 195.120). Large diameter taps and check valves should be designed to prevent damage to smart pigs. Tool launchers and receivers should be designed for the use of existing internal inspection technology.

Dead legs or intermittent flow piping shall be avoided or designed for internal corrosion monitoring and control. The pipeline should be designed to have flow conditions that will minimize the possibility of internal corrosion or erosion corrosion activity if the pipeline is to transport corrosive products.

4.1.4 COATING SYSTEMS

All newly constructed buried pipelines shall be externally coated. Some factors used in determining the proper coating to protect the pipeline system include: maximum expected service temperature, construction handling, pipe installation methods, pipe accessibility, soil stress resistance, backfill conditions, and chemical resistance. Refer to NACE International RP 0169 Section 5, Section 6.3.1 below, and DOT 49 *CFR* 195.238 for more information.

Pipeline coatings are to be applied per industry standards and pipeline operator specifications. Sufficient quality control and inspection shall be performed to guarantee that the coating has been properly applied to the metallic surface. Industry pipe coatings standards are referenced in Section 2.

For internal corrosion control, chemical inhibitor injection points and internal corrosion monitoring facilities shall be designed and installed for pipelines transporting corrosive products. Refer to NACE International RP 0175.

4.1.5 CONSTRUCTION

Coated pipe is to be properly stored and handled prior to installation per NACE International RP 0169 Section 5.2. All pipe coatings must be holiday tested before burial per NACE International RP 0188, RP 0274, and RP 0490, and DOT requirements (49 *CFR* 195.238(b)). Coating damage discovered by holiday testing is to be properly repaired before burial. Backfilling must be performed in a manner that protects the pipe coating from damage and provides firm support for the pipe (49 *CFR* 195.252). Rock shielding type material that does not shield cathodic protection may be wrapped around the pipe to minimize backfilling damage.

Foreign line test stations shall be installed with the cooperation of the foreign pipeline operator. Bonds and other methods are to be used where required to minimize interference currents from foreign pipeline cathodic protection systems or other DC current sources. Refer to NACE International RP 0169 (latest edition) Section 9. There must be at least twelve inches of clearance at foreign crossings. If twelve inches of clearance is not practical, adequate provisions must be made for corrosion control per DOT requirements (49 *CFR* 195.250).

The casing annulus is to be kept clean of any soil and debris during installation of the carrier pipe. All cased pipe is to be checked for proper isolation before and after burial. Casings shorted to the carrier pipe must be cleared before burial. Casing ends are to be properly sealed to keep out foreign material. The casing may be filled with inert gas or high dielectric material to keep out moisture. Test stations should be installed on the casing and the carrier pipe to monitor electrical isolation.

4.2 Coatings and Linings

All components in the pipeline system shall be coated with material suitable to prevent atmospheric corrosion damage. Refer to 49 *CFR* 195.416(i).

4.2.1 COATING SELECTION

The selection of protective coatings is based upon a variety of factors and concerns listed below:

- a. Environmental resistance.
- b. Color selection and appearance.
- c. Safety.
- d. Surface preparation requirements.
- e. Skill required to apply and maintain.
- f. Substrate to be coated.
- g. Maintenance cost.
- h. Consequences of coating failure.

- i. Regulatory restrictions on volatile organic compounds (VOCs).
- j. Waste disposal considerations.
- k. Compatibility with existing systems.
- l. Electrical resistance.
- m. Disbondment resistance.
- n. Abrasion resistance.
- o. Soil conditions.
- p. Operating temperatures.

4.2.2 COATING SYSTEM EVALUATIONS

Evaluations of the atmospheric coating systems on all structures should be conducted periodically. These evaluations should include the following items:

- a. Coating thickness.
- b. Condition and failure identification.
- c. Existing system type.
- d. Adhesion.
- e. Severity of any corrosion.
- f. Prevention of product contamination.

Evaluations should be performed by a knowledgeable person with experience in coating systems and inspection techniques. Evaluations should include a recommendation on what action, if any, needs to be taken to maintain or replace the coating system. The evaluation process may include a prioritizing process to rank the structures according to the quality of the coating system.

Protective coatings are applied to structures for a variety of reasons. The major ones are listed below:

- a. Protection of the structures from corrosion.
- b. Appearance.
- c. Regulatory requirements.
- d. Safety and operating efficiency.

Coatings provide protection through any one or more of the following processes:

- a. Prevent contact between structure and environment.
- b. Limit contact between structure and environment.
- c. Release inhibitors to mitigate attack.
- d. Provide a coating that is sacrificial to the substrate, such as galvanizing and zinc primer.
- e. Provide a non-conductive film to electrically isolate the structure.

4.2.3 SURFACE PREPARATION SPECIFICATIONS

New construction or the total recoating of an existing structure requires that the surface be cleaned in accordance with manufacturer's recommendations or company specifications before the coating is applied. Oil and grease should be removed from all surfaces to be coated prior to surface preparation in accordance with SSPC Specification SP-1. The surface prepa-

ration should achieve the desired profile and Steel Structures Painting Council (SSPC) or NACE International visual standard required for the coating system being applied. Coating applied to an improperly prepared surface will fail prematurely and expose the surface to possible corrosion attack.

When grit blasting is performed for surface preparation, the blast medium and existing paint systems may contain silica, lead, and asbestos or other hazardous materials; therefore, appropriate protective measures must be taken. Grit blast debris must be properly collected for disposal.

At all times while blasting is in progress, completely cover the following to protect against both direct blast effects and media entry:

- a. All tags.
- b. Labels.
- c. Glass covers.
- d. Pilot lights.
- e. Fire equipment.
- f. Fusible links on fire safety valves.
- g. Fire system detectors.
- h. Swivels.
- i. Meter heads.
- j. Valves with open stems and stem housings.
- k. Rubber seals.
- l. Pressure-vacuum vents.
- m. Motor drives.
- n. Motors.
- o. Pumps.
- p. Other delicate equipment.

4.2.4 INTERNAL TANK LINING

Steel storage tanks are often lined, depending on the material stored, to prevent failure due to internal corrosion attack. The complete interior of underground storage tanks is usually lined, while normally only the floor and a small portion of the adjacent shell surface on aboveground cone roof storage tanks is lined. On aboveground floating roof tanks, the floor, a larger portion of the adjacent shell surface, appurtenances, and the underside of the floating roof are usually lined.

The decision to line a tank interior should include the following considerations:

- a. Corrosion prevention.
- b. Tank design.
- c. Tank history.
- d. Commodity stored-corrosiveness or purity requirements.
- e. Environmental considerations.
- f. Service change.
- g. Upset conditions.
- h. Federal, state, and local regulations.
- i. API RP 652.
- j. Type of service (drain dry, maintained liquid bottom, or float roof).

Linings for tanks in petroleum service are normally divided into three classes: (a) Thin Film, (b) High-Build Film Linings, and (c) High-Build Reinforced Linings. Consider the following when selecting a lining system to install:

- a. Commodity chemical resistance.
- b. The severity of any previous corrosion damage that may require the tank bottom be reinforced.
- c. The degree of tank bottom flexing expected.
- d. Moisture resistance.
- e. Cost and existence of external ground side cathodic protection.

4.3 Routine External Corrosion Control

4.3.1 MONITORING

Cathodic protection levels of the pipeline must be monitored annually. During the annual survey the following tests should be performed on, but not limited to, the following: all power sources (rectifiers, sacrificial anodes, bonds, etc.), cased pipe, isolation flanges, along with tests to measure pipe-to-soil potentials at the established monitoring points along the pipeline. See also 49 *CFR* 195.416(b), including foreign pipeline crossings or parallel line conditions. If low cathodic protection levels exist, DOT requires that the cause of the problem be determined and a solution be implemented. Refer to 49 *CFR* 195.416(a).

Periodic monitoring of the condition of onshore above-ground piping, valves, meter stations, and tankage should be conducted. The pipeline operator decides if atmospheric conditions warrant increasing the inspection frequency of onshore pipeline facilities. Offshore atmospheric coatings should be inspected annually. Paint repairs are to be made in a timely manner to prevent serious atmospheric corrosion damage. Coating protection at the soil-air interface for onshore piping and at the splash zone on offshore piping is especially critical.

4.3.2 RECTIFIER INSPECTION

Rectifiers shall be inspected at intervals not exceeding 2.5 months but at least six times a calendar year. Interference bonds that are important to prevent serious interference problems should be checked bimonthly (six times a year). If a possible interference problem is detected during right-of-way inspections, close interval surveys, or the annual cathodic protection survey, action shall be taken to evaluate and correct the problem. Refer to 49 *CFR* 195.416(c).

4.3.3 OTHER INSPECTIONS

All pipeline operators shall, at intervals not exceeding five years, electrically inspect all bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is required [49 *CFR* 195.416(d)]. The type of electrical inspection

required by DOT is not specified. Many pipeline operators use the Earth Current Technique (Net Protective Current Criterion) to satisfy this DOT requirement. Refer to NACE International RP 0169 Section 6.2.2.2.1 for more information.

Cathodic protection systems must be maintained in proper operating order. Refer to NACE International RP 0169 Section 10 for additional information on the operation and maintenance of cathodic protection systems.

Electrically-shortened cased pipe should be monitored per company procedures. A shortened cased pipe may be cleared or filled with high dielectric filler, inert gas, or other methods to prevent corrosion activity from developing inside the cased pipe. Modifications to the vents may be desirable to minimize atmospheric corrosion activity. Information from metal loss surveys, if available, shall be used to monitor for atmospheric or electrolyte corrosion activity inside all cased pipe.

If the buried pipeline becomes exposed, an inspection should be performed and typically documented. Information on such a pipeline inspection report includes: coating condition, metallic pipe surface condition if exposed, and internal pipe surface condition if the pipe is cut open. Refer to 49 *CFR* 195.416(e).

Piping found to have corrosion damage out of tolerance shall be replaced or repaired unless the operating pressure is reduced to compensate for the remaining pipe strength (49 *CFR* 195.416(e), (f), (g), and (h)). If the pipeline operator considers it sound engineering practice, ASME B31G, modified B31G (R-streng) or other methods can be used to calculate the MOP of the corrosion-damaged pipe. Refer to 49 *CFR* 195.416(e), (f), and (g) for minimum requirements.

All EPA, OSHA, and other government regulations are to be followed when performing maintenance work on a pipeline coating containing asbestos.

4.3.4 CLOSE INTERVAL SURVEY

Close Interval Survey (CIS) is just one of a variety of techniques available to the owner/operator to evaluate the effectiveness of the corrosion control system. Smart pigs and Pearson survey are two other examples.

For pipelines having non-uniform coating deterioration, pipe-to-soil potentials at the test stations may not be representative of the cathodic protection level on the pipeline. A CIS can measure pipe-to-soil potentials between the test stations to give a more adequate indication of the true condition. Examples of CIS include: (a) continuous current, (b) interrupted current, and (c) cell-to-cell potential. The current interruption rate (on/off cycle) for interrupted-current CIS shall be set to minimize depolarization of the pipeline during the survey. The rate of data sampling shall be set to prevent erroneous data from voltage spiking.

CIS can be effective in locating: (a) stray current problems, (b) coating damage, and (c) areas of inadequate cathodic protection. Problem areas detected by CIS shall be corrected.

CIS is not effective in detecting corrosion activity due to disbanded coatings. In addition, localized corrosion activity on the bottom of large diameter pipe may not be detected.

The frequency of CIS should be based upon sound engineering judgement. Factors that may influence the frequency of CIS inspections include:

- a. Public safety.
- b. Environmental sensitivity.
- c. Microbiological Influenced Corrosion (MIC) activity.
- d. Soil stress activity.
- e. Coating deterioration rate.
- f. Commodity transported.
- g. Soil resistivity.
- h. Interference problems.

4.4 Routine Internal Corrosion Monitoring and Control Methods

Internal corrosion control programs for pipelines transporting corrosive products shall be established. Refer to 49 *CFR* 195.418.

Free water inside the pipeline can combine with carbon dioxide and hydrogen sulfide to form acids that can cause serious damage to the internal surfaces of the pipeline. Moisture condensing from petroleum products may cause corrosion of the internal surface of product pipelines. MIC can also cause serious internal corrosion problems for pipelines. Factors that influence the possibility of internal corrosion activity are:

- a. Flow regime.
- b. Pipeline location (low spots, hillsides, etc.).
- c. Pipeline operating temperature.
- d. Water content.
- e. Carbon dioxide and hydrogen sulfide content.
- f. Oxygen.
- g. Bacteria.
- h. Operating pressure.
- i. Sediment deposits.

Continuous injection, batch, or slug chemical treatment programs are ways to control internal corrosion for pipelines transporting corrosive products. Periodic running of scraper pigs may be required to prevent under-deposit corrosion activity due to corrosion deposits, scale, sand, or petroleum wax formation on the pipe internal surface that shield the pipe wall from chemical inhibitors. Pigging at the appropriate frequency and with the appropriate pig(s), will aid in removal of water and help control MIC.

The type of chemical treatment and the amount of chemical inhibitor required depends upon the flow conditions inside the pipeline. The effectiveness of the chemical inhibitor treatment must be monitored.

Some internal corrosion monitoring methods include:

- a. Weight loss coupons.
- b. Electrical probes.
- c. Galvanic probes.
- d. Hydrogen probes.
- e. Visual inspections.
- f. Test spools.
- g. Ultrasonic inspections of the pipe wall thickness measured externally.
- h. Ultrasonic and magnetic flux leakage internal inspection devices.
- i. Radiography.
- j. Water chemistry.

Water chemistry tests include:

- a. Iron concentration.
- b. Manganese concentration.
- c. pH.
- d. Bacteria levels.

- e. Oxygen levels.
- f. Carbon dioxide levels.
- g. Hydrogen sulfide levels.
- h. Chloride levels.
- i. Sulfate levels.
- j. Inhibitor residual.

If chemical inhibitor is used, DOT requires that the operator use coupons or other monitoring techniques to determine the effectiveness of the inhibitor. 49 *CFR* 195.418 requires corrosion coupons to be removed and examined at intervals not exceeding 7.5 months, but at least twice per calendar year.

All pipe removed from the pipeline system shall be inspected for internal corrosion damage and the results are typically documented. Refer to 49 *CFR* 195.418 (d).

Information from monitoring of internal corrosion activity shall be used to make adjustments to the internal corrosion control program as required.

SECTION 5—INSPECTION AND REVIEW

5.1 General

An inspection and review process should be developed to assure not only compliance with applicable regulations but also to extend assurances of overall integrity for the pipeline system. Inspection and review procedures in this section will be confined to those directly related to integrity assurance, but it should be recognized that numerous other inspections, reviews and audits are necessary and/or required in the areas of safety, industrial hygiene, and environmental protection.

5.1.1 REGULATORY REQUIREMENTS

The following DOT regulations (49 *CFR* Part 195) clearly spell out minimum inspection requirements and inspection frequencies in several key areas as follows:

- a. 195.412 Inspection of ROW and crossings under navigable waters.
- b. 195.414 Corrosion control (refer to Section 6).
- c. 195.416 External corrosion control.
- d. 195.418 Internal corrosion control.
- e. 195.420 Valve maintenance.
- f. 195.428 Overpressure safety devices.
- g. 195.432 Breakout tanks.

Other agencies including USCG, EPA, state and local jurisdictions may require inspections. It is incumbent on pipeline operators to assess and determine the applicability of regulatory requirements beyond those contained herein.

5.1.2 ADDITIONAL OPERATION AND MAINTENANCE INSPECTIONS

Integrity assurance practices should extend beyond these minimum required activities. Additional operation and maintenance inspections should be designed to include the following:

- a. Clear definitions of what is to be inspected.
- b. Determination of methods to comply with inspection frequency requirements.
- c. Performance measures, action plans and other documentation.
- d. Appropriately designed and used forms to facilitate such inspections.
- e. Training and deployment of qualified individuals to perform the inspections.

5.2 Risk Assessment

Risk assessment is an evaluation technique which attempts to define the most important factors that could lead to future problems through combination of statistical data, experience, and other resources. Such an assessment can become an effective means to identify and prevent problems (proactive) rather than to reacting after they have developed or occurred.

5.2.1 ANALYSIS

Risk evaluation can follow numerous approaches from sophisticated, highly data-oriented systems to more simple models, based on historical information and experience. Any

analysis should include the factors that are deemed to contribute to pipeline failures. The more significant failure contributors include:

- a. Third party damage.
- b. Corrosion.
- c. Operating errors.
- d. Manufacturing defects.
- e. Design/construction flaws.

Each of these factors could in turn include risk related items peculiar to that contributor.

5.2.1.1 Consequences

Consequences of failures should also be included in the analysis. Such factors must be included due to their potential impact on:

- a. Public and personnel health and safety.
- b. Environmental damage.
- c. Property and/or asset losses.

5.2.2 RESULTS

Through the combination and examination of all factors, using scoring/modeling techniques, the highest risk areas can be determined. Prioritizing or ranking of actions, including expenditures of funds or other resource allocations, can then be developed to address the higher risk areas first.

5.3 Hydrostatic Testing

5.3.1 GENERAL

49 *CFR* 195 Subpart E: "Pressure Testing" establishes minimum requirements for pressure testing various pipelines. API RP 1110 provides additional information to be considered during pressure testing. Refer also to ASME B31.4.

For integrity assurance purposes, hydrostatic testing is only one of the methods available to establish a pipeline's performance capability. Pipeline operators should also review appropriate integrity assurance measures, such as close interval surveys, internal pipeline inspections, and MOP reduction in addition to hydrostatic testing. Hydrostatic testing is used to verify structural integrity and the capability for containment of fluid. Hydrostatic testing used in combination with other inspection methods can provide an indication of the overall pipeline condition with excellent assurance of integrity.

49 *CFR* 195.303 defines the minimum test requirements to be at least a 4-hour continuous period at 125 percent or more of MOP (with an additional 4 continuous hours at 110 percent of MOP for pipelines that are not visually inspected for leakage), including written certification that documents the pressure recording, pressure calibration, and any reconciliation which validates the test. Hydrostatic testing provides a practical means to test the integrity of pipe, longitudinal seam

welds, if any, and to a lesser extent girth welds. In addition to hydrostatic testing, proof pressure testing checks may be conducted on an existing pipeline or piping segment for shorter durations during routine shutdown periods at sufficient pressure levels to assure leak tightness.

5.3.2 EFFECTIVENESS

While a hydrostatic test provides a demonstration of the current minimum pressure rating of a pipeline system, certain defects or imperfections and their characteristics must be considered. Defects which are currently large enough to cause failure at pressure levels up to and including the test pressure will usually be revealed and eliminated. Consequently, the higher the ratio of test pressure to MOP, the more effective the test is at documenting a pipeline's integrity because the difference between the sizes of defects that can remain after the test and those which would fail at the MOP becomes ever larger. A practical upper limit on test pressure is imposed by the need to avoid expanding or damaging otherwise sound pipe and/or its protective coating. Experience has shown that the minimum test pressure-to-operating pressure ratio imposed by the federal regulations (namely, 125 percent) provides an adequate demonstration of current pipeline integrity.

It is important to recognize certain limitations of hydrostatic testing. These limitations include:

- a. Anomalies or imperfections that are too small to fail a test pressure will not be revealed.
- b. Small defects that may become larger during subsequent operation of the pipeline could eventually become large enough to fail.
- c. Defects with failure pressures at or slightly above target test pressure that may become enlarged during the test without failing.

These latter defects may subsequently fail at pressure levels below that of the test which negates some of the margin of safety established by the hydrostatic test. This phenomenon is called a "pressure reversal."

CAUTION: Pipeline operators should be aware of the potential for pressure reversal phenomenon especially when testing some older vintages of pipe.

In order to gain the maximum effectiveness from hydrostatic testing and prior to design of such a test, pipeline operators should thoroughly evaluate each pipeline segment and/or pipeline components with respect to potential defect behavior.

5.3.3 HYDROSTATIC TESTING PROGRAMS

A formalized program to pressure test lines already in service should consider:

- a. Age of pipe.
- b. Commodity handled.

- c. Type of pipe (manufacturing process):
 - 1. Lapweld.
 - 2. Pre-1970 ERW (electric resistance welding process).
 - 3. Post-1970 ERW.
 - 4. DSAW (double submerged arc welding process).
 - 5. Seamless.
- d. Known coating problems and cathodic protection history.
- e. Areas traversed:
 - 1. Environmentally sensitive.
 - 2. Population density.
 - 3. State regulations applicability.
 - 4. Watercrossings.
- f. Previous hydrostatic test.
- g. Failure history/failure analyses.
- h. Operating conditions.
- i. Internal inspection surveys.

Following the consideration of the above factors, a prioritized testing schedule can be developed. In general, give first priority to pipelines that have never been subjected to the minimum acceptable hydrostatic test defined above and second priority to those pipelines that may have been tested but their records have been lost. However, the actual prioritizing may be based on the operator's assessment of risk peculiar to the operator's own system. Reference 49 *CFR* 195 Subpart E.

5.3.4 IMPLEMENTATION

The factors developed above should become the basis for establishing a prioritized hydrostatic testing schedule. The unique characteristics and history of each pipeline segment will need to be taken into account; the overall prioritizing criteria must be based on sound engineering analysis. Gaining access to, and disposal of, test water or other test media will need special consideration and permitting. While most test programs would be expected to use water, other media may be considered, such as crude oil and refined products. Use of other media must follow the requirements set forth in 49 *CFR* Part 195.306.

The pipeline operator should consider limiting the lengths of test sections in areas of large elevation differences so that the target test pressure can be achieved without causing damage to the portion of the pipeline at low elevations. It is desirable to subject as much of the pipeline as possible to the highest pressures.

5.3.5 EFFECTS OF HYDROTESTING

The most common causes of failure that may be expected to occur during hydrotesting are:

- a. Corrosion.
- b. Third party damage.
- c. Manufacturing defects.
- d. Operationally induced defects.

Hydrostatic testing may not identify all structural anomalies contained in a pipeline segment. Defects that remain after a test may be subject to enlargement in service. For example, corrosion pits may become larger because corrosion at undiscovered areas of pitting cannot be mitigated. Frequent large pressure fluctuations in service may cause remaining flaws to grow by fatigue crack growth. If a pipeline has had a history of service or test failures from manufacturing defects, a thorough metallurgical examination should be considered during testing or after the line is back in service to assess the cause and the potential for enlargement of such flaws.

5.4 Internal Inspection

5.4.1 GENERAL

Internal inspection of a pipeline for the purpose of detecting possible pipe anomalies is a useful procedure that can be performed without taking the pipeline out of service. Most internal inspection tools are also equipped with supplementary distance-verifying devices such as girth weld detectors and detectors that respond to above-ground signal generators strategically placed at known locations along the pipeline.

Note: Extra care should be taken to accurately record and define above-ground distances to minimize subsequent difficulties in locating anomalies.

Besides the in-line tools described above, there exists another class of inspection devices that can be pulled through a pipeline by means of a winch cable or crawl under their own power. However, the pipeline must be out of service for such an inspection, and the amount of pipeline that these tools can inspect is limited to short distances.

5.4.2 ANOMALY CHARACTERIZATION

In-line tools are used to locate and, to some extent, characterize anomalies in the pipeline that may affect pipeline integrity. The results of an inspection are used to plan and prioritize a repair or replacement program for the detected anomalies that appear to be of a nature or extent that could have a significant affect on pipeline integrity. Such anomalies are usually repaired or removed from the pipeline.

The next level of repair, that may be carried out over several months or a few years, addresses important anomalies that are not severe enough to require a near-term repair or removal. These anomalies usually do not require removal, and they can usually be remedied by repairs to the coating of the pipeline or removal of debris in the bedding or backfill.

The last level of response usually applies to anomalies that are judged to be insignificant. Anomalies that are judged to be insignificant can be left until another in-line inspection is conducted, at which time they can be reevaluated if necessary.

5.4.3 FREQUENCY OF INSPECTION OR INSPECTION PLANNING

The frequency of metal loss tool inspections should be based upon sound engineering judgment by the pipeline operator using the principles of risk management. The following items are typically considered in developing an internal inspection program:

5.4.3.1 Representative Items of Group Failure Issues

- a. Pipeline age.
- b. Cathodic protection levels.
- c. Coating condition and type.
- d. Condition of the pipeline reported by the last internal inspection.
- e. Leak history.
- f. Microbiological influenced corrosion (MIC) activity.
- g. Soil type and resistivity.
- h. Soil stress activity.
- i. Population densities.

5.4.3.2 Representative Items of Consequence Issues

- a. Location and use of public buildings.
- b. Environmental considerations.
- c. Products transported.

5.4.4 IN-LINE INSPECTION CAPABILITIES

In-line tools exist that can reliably locate and, to varying extents, characterize corrosion-caused metal loss (both external and internal), some laminations, hard spots, dents, cracks, bends, ovalities, areas of settlement, and other mechanical damage to the pipe wall. Tools that can reliably find metal loss are based either on magnetic flux leakage technology or ultrasonic pulse-echo technology. Tools that can detect dents or other geometric anomalies generally rely on mechanical calipers or sonar, but the magnetic flux tools sometimes locate dents through secondary effects.

No single tool can perform all desired detection functions. Also, the performance of a given tool or technology may vary with the nature of the pipeline and its operating characteristics. Experience suggests that in-line tool inspection programs are most successful when they are used regularly by pipeline operators. Operators who make regular use of in-line tool inspections tend to develop in-house risk assessment capabilities for effective tool use.

5.4.5 LIMITATIONS

In-line tools require launching and receiving facilities that may not exist on some pipelines. Many pipelines contain sharp bends, side taps without bars, penetrations, size

changes and valve restrictions that can restrict the use of normal inspection tools. Pipelines regulated by 49 *CFR* 195.120 require that all new sections, and most modified sections, of existing pipelines be designed and constructed to accommodate internal inspection devices.

5.4.6 OPERATING CONSIDERATIONS

The running of in-line tools may require alterations to normal pipeline operations. One or more cleaning pigs should be run prior to an in-line tool run to remove wax from crude oil pipelines and to remove wax, debris, dirt and any corrosion products from any pipeline. At times, a magnetic pig is run to pick up stray bits of metal such as welding rods. It may also be necessary to run a "gauging" pig, caliper tool, and/or dummy tool to assure that the in-line inspection tool will pass freely through the pipeline.

To run in-line tools effectively it may be necessary to control the flow rates. In particular, the velocity restrictions often necessitate temporary reductions in throughput for natural gas pipelines. Throttling may be necessary to maintain the tool velocity within specified parameters in liquid lines located in mountainous terrains.

Several other preparatory actions may be required to run an in-line tool. Pipeline operators are cautioned to check the positions of ball or gate valves; check valves may have to be blocked open; a launcher or a receiver may have to be added if none exists at required locations; aboveground marker devices will have to be placed and located, where needed, by survey stationing; and launching and running should be coordinated with dispatchers and/or controllers.

After the tool run, the pipeline operator should be prepared to examine the results as quickly as they become available and to respond appropriately in the event that potentially severe defects are discovered.

5.4.7 CORRELATION OF IN-LINE INSPECTION AND CLOSE INTERVAL SURVEYS

Metal-loss tools are more effective than CIS inspection at finding corrosion activity caused by shielding of disbonded pipeline coatings. In addition, metal-loss smart pigs may find localized corrosion activity that was not detected by a CIS inspection. The pipeline operator needs to consider the cost effectiveness of internal inspection devices and other inspection options and the advantages of combining various inspection methods.

CIS and internal inspection device data can be combined to improve the corrosion control program of a pipeline. CIS data informs the pipeline operator where cathodic protection levels need to be improved. Metal-loss tool data informs the pipeline operator of locations where corrosion has occurred and locations where pipe may need to be repaired or replaced. These two inspection methods work very well together. The pipeline operator should make sound engineering decisions on the economical use of these two inspection methods to

detect corrosion problems that are believed to exist in the pipeline system.

5.5 Tank Integrity

Aboveground storage tanks are an integral part of a pipeline transportation system. They provide an effective means of segregating various product grades, handling volume adjustments necessary to accommodate scheduling and product movement requirements, and simply providing storage until the product can be delivered out of the pipeline system. While these tanks provide a safe, effective means of storing petroleum products, they can pose environmental and economic risks. To help pipeline operators minimize those risks, API has developed a number of recommended practices and standards that cover the maintenance, inspection, and repair of storage tanks. These publications include:

- a. API RP 651.
- b. API RP 652.
- c. API Std 653.
- d. API Std 2510.
- e. API Std 2610.

API Std 2610 is a "compilation of industry knowledge, information, and management practices for all relevant aspects of terminal and tank operations aggregated into an overview document comprising best practices." It is the best available resource for information on tank integrity issues, standards, and recommended practices, covering all the above-mentioned API standards and recommended practices, as well as other API and government standards and publications.

API Std 653 covers major out-of-service inspections which are usually performed on a long term planned basis.

DOT 49 *CFR* Part 195.432 also requires inspection of atmospheric and pressure tanks.

The requirements in these standards should be followed; where applicable codes or regulations are more stringent, such codes shall be adhered to and supersede the above-mentioned standards.

5.6 Other Reviews and Analyses

5.6.1 REVIEWS

Minimum requirements for review of crucial information and instructions are also contained in 49 *CFR* 195 and include:

- a. 195.402 Maintenance and operating manuals and emergency response.
- b. 195.403 Training.

5.6.2 AUDITS

Performing audits related to integrity assurance activities provides another means to assure overall program effectiveness. It should be noted that audits may be used to assess

many areas beyond just compliance. Compliance audits fall into two categories:

- a. Regulatory compliance audits.
- b. Internal compliance audits.

5.6.2.1 In responding to and participating in these audits, the following will improve the value of these experiences:

- a. Assure up-to-date documentation is completed and maintained.
- b. Design and implement a system to file documentation and facilitate its ease of retrieval.
- c. Train appropriate personnel in proper documentation procedures and the use of the filing/retrieval system.
- d. Be prepared to match documentation and actual practice.
- e. Take timely corrective action on any discovered deficiencies.

5.6.2.2 Use of this technique should be a precursor to the more formal and impactful compliance agency audits. When properly carried out, these audits will lead to smoother, less disruptive responses. The audits should include features such as:

- a. Have a positive perspective, where the process is used to improve performance as opposed to a disruptive ordeal.
- b. Be designed to assess the overall effectiveness of compliance processes versus merely checking pieces of data and regulatory details.
- c. Provide constructive feedback at the action level with follow-up to assure corrective action is taken.
- d. Combine other compliance audits of concern areas such as safety, industrial hygiene and environmental protection to improve efficiency of the audit process and lessen the disruption of day-to-day operations.

5.6.3 FAILURE ANALYSES

In order to determine the cause and effect relationships of various failures, pipeline operators should seek in-house or third party laboratory analyses such as:

- a. Metallurgical examination of pipe, flange, bolting, fitting or weld deterioration or failure.
- b. Metallurgical/electrical examination of unexplained machinery failure.
- c. Other laboratory analyses or examination of various failures.

5.6.4 OTHER ANALYSES/REVIEWS

Other analyses/reviews could include the following:

- a. Metallurgical or laboratory examination of unexplained corrosion deterioration.
- b. Analysis of coating failures.
- c. Engineering review of power related equipment or wiring failures or deterioration.
- d. Analysis of unexplained machinery vibration or deterioration.

Results of these reviews and analyses will provide cause/effect relationships and/or lessons learned so as to mitigate

future occurrences and thereby assure integrity through problem resolution and proactive responses.

SECTION 6—DAMAGE PREVENTION

6.1 General

While the earlier sections in this recommended practice focus on methods to ensure that the physical components of a pipeline facility are constructed and maintained in a safe and sound manner, this section deals with methods for reducing the risk of damage to the facilities from outside forces. Pipeline operators should establish damage prevention programs to ensure that these risks are minimized.

6.2 Surveillance

6.2.1 ONE-CALL SYSTEMS

Notification and underground facility location should be handled through a centralized program. Some pipeline operators, particularly those whose pipelines are located in rural areas where there is little construction activity, may elect to set up an in-house apparatus for handling calls from excavators, and coordinate the location and marking of underground pipelines. The most common method of handling notification, however, is through operator-sponsored centralized programs known as one-call systems. The one-call system has been defined as a communication system established by two or more utilities, governmental agencies, or other operators of underground facilities, to provide one telephone number for excavating contractors and the general public to call for notification of their intent to use equipment for excavating, tunneling, demolition, or any other similar work. The one-call system provides the participating members an opportunity to identify and locate their underground facilities and be present to observe excavation near the facilities.

Note: Pipeline operator companies support mandatory participation in available and effective one-call systems.

6.2.2 AERIAL SURVEILLANCE

Due to the large distances covered by pipelines, patrol of their rights-of-way (ROW) is often performed using aircraft. These may either be light, fixed-wing aircraft or helicopters. During the patrol, a pilot or an observer monitors the ROW looking for evidence of hydrocarbons, damage to the ground surface, structures built on the ROW, construction activity in the vicinity of the pipeline, or any other abnormal activity which could endanger the pipeline. A report of the patrol is generated and used for follow-up activities if required.

6.2.3 GROUND SURVEILLANCE

In some areas, the monitoring of the ROW must either be done on foot or by ground vehicle because aircraft use may be restricted, or they may be unsafe to operate in the area due to weather conditions during certain times of the year. Ground surveillance in addition to aerial surveillance may be used in unusual situations to provide a closer observation. Ground surveillance allows for more detailed inspection, which is helpful in planning maintenance activities and picking up integrity issues too small to be seen from the air.

6.3 Facility Marking and Maintenance

6.3.1 ROW AND FACILITY MARKING

A general description, and use and placement of line markers and signs for below ground and aboveground pipelines and facilities is specified in 49 *CFR* 195.410 and 195.434. For further information on these requirements and other good management practices, refer to API RP 1109.

6.3.2 ROW CLEARING

In areas along the ROW where trees, brush and other vegetation can obscure the visibility and accessibility, a regular ROW clearing program should be maintained.

There are three major types of vegetation management operations tailored to meet the needs of a right-of-way program. Many times all three are used in combination to provide a cost effective program while adhering to environmental and public sensitivities. The three major categories are:

- a. Grass/brush cutting.
- b. Side trimming.
- c. Herbicide spraying.

6.3.2.1 Grass and brush cutting is the most commonly used maintenance technique on the majority of systems. Mechanical as well as manual operations are used by many in-house and contract crews.

6.3.2.2 Where tree encroachment is a problem some side trimming alternatives to consider are:

- a. Aerial lift devices.
- b. Telescoping and knuckle booms.
- c. Manual climbing crews.

6.3.2.3 Herbicides can be used for control of undesirable brush and weeds and for tree encroachment. Where used properly herbicides are safe, effective, and the most economical of all techniques in a long term program. Many herbicide programs are used in conjunction with current mechanical programs to provide cost-effective results.

The ROW clearing program requires advance planning. Environmental specialists and land personnel should be consulted to ensure that the proper permits are obtained from regulatory agencies and permission is obtained from landowners.

6.3.3 ENCROACHMENT MITIGATION

Regardless of the efforts made in the original construction of the pipeline to locate the pipeline at a safe distance from other structures, pipeline operators at times have limited control over landowners' and others' abilities and rights to build near the pipeline after it is in place. Through existing regulatory requirements and industry operating and maintenance practices, several methods exist to minimize the possibility of someone unknowingly encroaching on a petroleum pipeline. For example, through pipeline marking and public awareness programs, pipeline companies make the location of their pipelines known and provide landowners with contact numbers so that any construction plans around the pipelines can be discussed in advance. Through aerial and ground surveillance, operators stay aware of activities that potentially can affect their pipelines. Since encroachments often threaten the integrity of the pipeline, increase the risks associated with operating the pipeline, and limit a pipeline operator's ability to adequately respond to an emergency, pipeline operators should monitor construction activity in the area of their pipelines and take appropriate action, where possible, to limit unreasonable encroachments.

6.4 Public Education and Communication

49 *CFR* 195.440 requires that each pipeline operator establish a continuing education program to enable the public, appropriate government organizations and individuals engaged in excavation related activities to recognize a hazardous liquid pipeline emergency and to report it to the pipeline operator, the fire department, police, or other appropriate public safety officials. Refer to *CFR* 195.402(c)(12).

6.4.1 The pipeline industry, through API, (reference API RP 1123) has for many years taken an active role in sponsoring various programs to help pipeline operators meet community awareness objectives. An API committee has been created to specifically address community awareness concerns. Some API efforts in this regard include:

- a. Sponsoring radio and television public service announcements (PSAs). Solicitations have included hundreds of radio and television stations across the country.
- b. Printing excavation warning decals to alert construction equipment operators of the need to check for the presence of underground pipelines.
- c. Mailings to landowners to advise of pending maintenance activities.
- d. Producing a joint API/WSPA pipeline video, *Quiet Steel*. This 10-minute video informs local officials about pipeline operations and their important role in the community.
- e. Development of the brochure, *Safety Guideline for People Who Live and Work Near Petroleum Pipelines*, that was first published in 1990.
- f. Development of a recommended practice to help pipeline operators prepare coordinated emergency preparedness plans, with an entire chapter devoted to specific coordination efforts with local communities.
- g. Production of an API pipeline video, *Responding to Pipeline Emergencies*. This video informs local officials about responding to pipeline emergencies.
- h. Liaison with local fire departments and other local officials.

6.4.2 In addition to their participation in API sponsored programs, pipeline operators, have developed numerous additional methods for increasing community awareness of pipeline safety. Typical programs include:

- a. Periodically contacting local fire departments, police departments, county officials, and other emergency response agencies, often with facility tours arranged.
- b. Distributing pipeline safety information (such as letters, brochures, decals, calendars, API publications and imprinted novelty items) to those who live close to the pipeline, and to excavators.
- c. Distributing safety brochures and pipeline maps to various local government and emergency response agencies.
- d. Periodically meeting with residents and excavators during normal pipeline maintenance and operations activities.
- e. Participating in joint mock emergencies (drills) with various community emergency response agencies.

Community awareness programs can be tailored for, and directed to, a particular audience (for example, contractors, community officials, emergency response agencies, and the public) by the use of direct mail services. Mailings can be made to narrow corridors along the pipeline by use of tools such as zip code and carrier route mailings provided by direct mail service companies.

APPENDIX A—BIBLIOGRAPHY

Inclusion herein is for guideline reference only unless otherwise stated and is not intended to require a pipeline operator to adopt all or part of the reference source.

API

- Std 510 *Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*
- Publ 2201 *Procedures for Welding or Hot Tapping on Equipment Containing Flammables*
- ANSI/API 570 *Piping Inspection Code*

ACI

- 318 *Building Code Requirements for Reinforced Concrete*

AISC

- Steel Construction Manual*

ASME

- B31G *Manual for Determining the Remaining Strength of Corroded Pipelines*

ASTM

- Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method*

AWWA

- ANSI/AWWA C209 *Cold Applied Tape Coatings for the External of Special Sections, Connections, and Fittings for Steel Water Pipelines*
- ANSI/AWWA C217 *Cold Applied Petroleum Tape and Petroleum Wax Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Buried Steel Water Pipelines*

DOT

- 49 CFR 190 *Pipeline Safety Program Procedures*

GRI

G. J. Posakony and V. L. Hill, "Assuring the Integrity of Natural Gas Transmission Pipelines," GRI 1992.

T. A. Bubenik, S. B. Nestleroth, R. J. Eiber, and B. F. Saffell, "Magnetic Flux Leakage (MFL) Technology for Natural Gas Pipeline Inspection," GRI, 1992.

A. E. Crouch, "In-Line Inspection of Natural Gas Pipelines," GRI, 1993.

H. E. Stewart and M. T. Behn, "User's Guide for PC-PISCESL (Personal Computer—Pipeline Soil Crossing Evaluation System Liquids) Version 1.1," GRI-Stoner Associates Inc. (in conjunction w/ Cornell Univ.), 1993.

H. E. Stewart and M. T. Behn, "User's Guide for PC-PISCES (Personal Computer—Pipeline Soil Crossing Evaluation Systems)" *Gas Pipelines*, GRI - Stoner Associates Inc. (in conjunction w/Cornell Univ.), 1993.

D. Pope, "Microbiologically Influenced Corrosion (MIC): Methods of Detection in the Field," *GRI Field Guide 1988*, GRI-Radian, 1988.

NACE International

- TM0172 *Antirust Properties of Cargoes in Petroleum Product Pipelines*
- RP0177 *Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems*
- RP0387 *Metallurgical and Inspection Requirements for Cast Sacrificial Anodes for Offshore Applications*
- RP0274 *High-Voltage Electrical Inspection of Pipeline Coatings Prior to Installation*
- RP0184 *Repair of Lining Systems*

- RP0775 *Preparation and Installation of Corrosion Coupons and Interpretation of Test Data in Oil Field Operations*
 RP0288 *Inspection of Linings on Steel and Concrete*
 RP0192 *Monitoring Corrosion in Oil and Gas Production with Iron Counts*

NAPCA

- Bull 2-66-91 *Standard Applied Pipe Coating Weights for NAPCA Coating Specifications*
 Bull 3-67-91 *External Application Procedures of Hot Applied Coal Tar Coatings to Steel Pipe Bull 5-69-91, NAPCA Specifications for Pipe Wrappers*
 Bull 12-78-90 *External Application Procedures for Plant Applied Fusion Bonded Epoxy (FBE) Coatings to Steel Pipe*
 Bull 13-79-90 *External Application Procedures for Coal Tar Epoxy Protective Coatings to Steel Pipe*
 Bull 14-83-90 *External Application Procedures for Polyolefin Pipe Coating Applied by the Cross Head Extrusion Method or the Side Extrusion Method to Steel Pipe*
 Bull 15-83-90 *External Application Procedures for Plant Applied Tape Coating to Steel Pipe*
 Bull 6-69-90-1 *Suggested Procedures to Hand Wrap Field Joints using Hot Enamel*
 Bull 6-69-90-2 *Suggested Procedures for Coating of Girth Welds with Fusion Bonded Epoxy*
 Bull 6-69-90-3 *Suggested Procedures for Coating Field Joints, Fittings, Connections, and Pre-fabricated Sections using Tape Coatings*
 Bull 6-69-90-4 *Suggested Procedure for Field Joint Application using Mastic Mix and Field Mold*
 Bull 6-69-90-5 *Suggested Procedure for Coating Field Joints using Heat Shrinkable Materials*

SSPC

- SSPC-SP2 *Hard Tool Cleaning*
 SSPC-SP3 *White Metal Blast Cleaning*
 SSPC-SP6 *Commercial Blast Cleaning*
 SSPC-SP7 *Brush-off Blast Cleaning*
 SSPC-SP10 *Near White Metal Blast Cleaning*
 SSPC-SP11 *Hand Tool/Power Cleaning*

EXHIBIT A – 2

§ 195.307**§ 195.307 Pressure testing above-ground breakout tanks.**

(a) For aboveground breakout tanks built to API Specification 12F and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of API Specification 12F.

(b) For aboveground breakout tanks built to API Standard 620 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.18 of API Standard 620.

(c) For aboveground breakout tanks built to API Standard 650 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.3 of API Standard 650.

(d) For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C that are returned to service after October 2, 2000, the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 10.3 of API Standard 653.

(e) For aboveground breakout tanks built to API Standard 2510 and first placed in service after October 2, 2000, pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.

[Amdt. 195-66, 64 FR 15936, Apr. 2, 1999]

§ 195.308 Testing of tie-ins.

Pipe associated with tie-ins must be pressure tested, either with the section to be tied in or separately.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by 195-51, 59 FR 29385, June 7, 1994]

§ 195.310 Records.

(a) A record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.

(b) The record required by paragraph (a) of this section must include:

- (1) The pressure recording charts;
- (2) Test instrument calibration data;
- (3) The name of the operator, the name of the person responsible for

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making the test, and the name of the test company used, if any;

- (4) The date and time of the test;
- (5) The minimum test pressure;
- (6) The test medium;
- (7) A description of the facility tested and the test apparatus;
- (8) An explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts; and
- (9) Where elevation differences in the section under test exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

[Amdt. 195-34, 50 FR 34474, Aug. 26, 1985, as amended by Amdt. 195-51, 59 FR 29385, June 7, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

Subpart F—Operation and Maintenance**§ 195.400 Scope.**

This subpart prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe.

§ 195.401 General requirements.

(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under § 195.402(a) of this subpart.

(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(c) Except as provided in § 195.5, no operator may operate any part of any of the following pipelines unless it was designed and constructed as required by this part:

- (1) An interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid.
- (2) An interstate offshore gathering line, other than a low-stress pipeline, on which construction was begun after

EXHIBIT A – 3

Date: Thursday, May 10, 2001 2:04:06 PM
From: Lloyd.Ulrich@rspa.dot.gov
Subj: Inquiry
To: ezsafeoil@aol.com

You asked:

For a pipeline laid in 1942 at about 14" of cover, if the line is now both (1) uprated in operating pressure, and (2) converted to Hazardous Liquid / LPG service from crude oil service (i.e., from Part 194 to Part 195 service),
can the line still be operated at the original depth?

My technical answer is "yes." If you want an official, legal answer, write to Richard Hurlaux, Manager, Regulations, Office of Pipeline Safety (DPS-12), Department of Transportation, 400 7th Street S.W., Washington, DC 20590.

The pipeline was constructed in 1942 which was before the safety regulation over hazardous liquid pipelines in 49 CFR part 195 went into effect (1970) so

the pipeline is "grandfather." The regulation on cover is a construction rule, not an operating rule, so it only applies at the time of construction, which in this case was before the regulations were in effect. However, the

pipeline is subject to the operating rules if operated above 20% of SMYS - YES ①

and may be subject to the operating rules if operated at or below 20% of SMYS and one rule, section 195.401, states "Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time" Depending on the location of the pipeline, 14" cover may constitute a "condition that could adversely affect the safe operation" since the cover for a new pipeline buried where there is normal excavation (as opposed to rock excavation) is

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anywhere from 30" in rural areas to 36" in industrial, commercial, and residential areas. The operator would have to determine this.

NOTE: All hazardous liquid pipelines are subject to the safety regulations in Part 195 including crude oil pipelines. Part 194 covers response plans for oil pipelines in case of a spill from a pipeline, not safety standards over oil pipelines.

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Department of Transportation
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Return-Path: <lloyd.ulrich@RSPA.dot.gov>
Received: from rly-xb04.mx.aol.com (rly-xb04.mail.aol.com [172.20.105.105]) by air-xb03.mail.aol.com (v77_r1.36) with ESMTP; Thu, 10 May 2001 15:04:06 -0400
Received: from mh1.dot.gov (mh1.dot.gov [152.119.25.210]) by rly-xb04.mx.aol.com (v77_r1.36) with ESMTP; Thu, 10 May 2001 15:03:35 -0400
Received: from mdspxy02.dot.gov by mh1.dot.gov with ESMTP for ezsafeoil@aol.com; Thu, 10 May 2001 15:02:57 -0400
Received: from rspa_exchange.rspa.dot.gov ([127.0.0.1]) by mdspxy02.dot.gov (Netscape Messaging Server 4.15) with ESMTP id GD4VLY02.04H for <ezsafeoil@aol.com>; Thu, 10 May 2001 15:03:34 -0400
Received: by rspa_exchange.rspa.dot.gov with Internet Mail Service (5.5.2650.21) id <KB3SQYRG>; Thu, 10 May 2001 14:59:46 -0400
Message-Id: <748A54654C1FD5119B6100B0D049FCF12EB585@rspa_exchange.rspa.dot.gov>
From: "Lloyd Ulrich" <Lloyd.Ulrich@rspa.dot.gov>
To: "ezsafeoil@aol.com" <ezsafeoil@aol.com>
Subject: Inquiry
Date: Thu, 10 May 2001 14:59:45 -0400
MIME-Version: 1.0
X-Mailer: Internet Mail Service (5.5.2650.21)
Content-Type: text/plain

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Page 2

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EXHIBIT A – 4

RISK MANAGEMENT WITHIN THE LIQUID PIPELINE INDUSTRY

A Report from
**The Joint Government / Industry
Risk Assessment Quality Team**

Sponsored by
**The Office of Pipeline Safety (OPS)
and
The American Petroleum Institute (API)**

**Final Report
June 20, 1995**

EXHIBIT A – 5

9. WHAT ACTIONS SHOULD BE TAKEN?

To promote the cost-effective development of risk management within the liquid pipeline industry and the government, the RAQT suggests that the following actions be taken:

1. *API should develop a Recommended Practice for the liquid pipeline industry that describes the essential elements of an overall Risk Management program.*

This Guidelines should emphasize that risk management is a *management program*, not just a technical model for assessing likelihood or consequences of pipeline accidents. Accordingly, the Guidelines should be built upon a standard program format similar to that provided in API Specification Q1, Specification for Quality Programs. An example of a Risk Management program specification constructed on the Q1 framework is provided in Appendix D.

The Guidelines should incorporate the graded approach to risk management including the use of a Hazard Screening Model, including specifications for risk management processes and models for each level of risk management.

The Guidelines should include a description of the various types of possible risk management application and the technical requirements (model and data needs) necessary to support each type of application.

The Guidelines should also include requirements for self-assessment and both process-oriented performance metrics to be used by the pipeline operator to measure the extent to which the operator has fully implemented the risk management program.

2. *The OPS should develop risk-based regulations and incorporate by reference the API Risk Management Guidelines into its regulations.*

The OPS should begin to re-formulate its regulatory structure to allow flexibility in compliance where the application of risk management programs demonstrates that equal or greater levels of safety and environmental protection can be achieved. Ongoing rule making should be revised in those areas amenable to risk-based regulation. Upon appropriate review and approval, OPS should reference the API guidelines within these pipeline safety regulations as the specification for an acceptable risk management program. Risk Management programs that are developed consistent with the API guidelines can be used to obtain flexibility under the revised regulatory framework. The OPS should establish timelines for re-review of pipeline risk management programs, including required reviews after a significant accident.

EXHIBIT A – 6

B-283853

OPS Is Moving to Implement Risk Management Into Its Regulatory Framework

Even though the demonstration program is still ongoing and its safety and environmental benefits have not yet been quantified, OPS has proposed a rule that draws, in part, on the agency's experiences with the demonstration program to incorporate the use of a risk management approach in pipeline safety regulations.¹³ The proposed rule would affect hazardous liquid pipeline companies (companies that operate systems of 500 miles or more) that have pipelines in "high-consequence areas." The rule defines these areas as populated areas, environmentally sensitive areas, or commercially navigable waterways.¹⁴ OPS estimates that the rule would apply to 66 pipeline companies that operate about 87 percent of the nation's hazardous liquid pipeline mileage. All pipeline operators would still be required to follow the current minimum regulations.

Companies affected by this rule would be required to develop an "integrity management program" to comprehensively examine pipelines in high-consequence areas to identify and address potential risks. Such a program would include, among other things, (1) a plan for assessing the condition of pipelines in these areas, (2) periodic reassessments of the pipelines, (3) criteria for repairing deficiencies discovered through the assessments, and (4) measures of the program's effectiveness. Methods to assess the condition of the pipelines include internal inspections using "smart pigs" (devices that can travel through the pipelines to detect flaws) and hydrostatic testing (draining the pipeline, filling it with water, and increasing the pressure within the pipeline to identify weak points).

OPS intends to review companies' integrity management programs, including the risks identified by the companies and their strategies for addressing the risks. Although OPS officials have not determined exactly how these reviews will be integrated into the agency's periodic inspections of pipeline companies, they told us the reviews would require additional personnel. OPS officials could not estimate how many additional staff would eventually be needed. The agency has requested four additional staff

¹³The proposed rule also draws on the agency's experiences in inspecting pipeline companies' entire operating systems (described in the next section), investigating accidents, and conducting system integrity initiatives.

¹⁴According to OPS officials, the initial rule would affect operators of large hazardous liquid pipeline systems because OPS has gained familiarity with their operations through the risk management demonstration program. Subsequent rules would affect operators of small hazardous liquid pipelines and natural gas transmission pipelines in high-consequence areas.

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for fiscal year 2001, and OPS officials expect to request more in future years. In addition, agency officials told us that OPS is considering hiring contractors to assist with these reviews.

Several actions must occur before OPS can fully implement this new approach to regulating pipeline safety. OPS issued a proposed rule on April 24, 2000, and must incorporate comments from the industry and the public in a final rule. OPS must also complete another rule on the definition of areas that are unusually sensitive to environmental damage before it can identify high-consequence areas.¹⁵ In addition, OPS must develop guidelines for reviewing companies' integrity management programs and hire and train the additional staff needed to conduct the reviews. Meanwhile, the companies that have pipelines in high-consequence areas must develop their programs and assess the current condition of their pipelines. OPS estimates that pipeline companies will develop plans for assessing the condition of their pipelines by September 2001 and that the assessments will be complete by September 2007. (See table 2.)

Table 2: Milestones for Implementing a Risk Management Approach for Regulating Large Hazardous Liquid Pipelines

Date	Action
April 2000	OPS issued a proposed rule requiring enhanced protection of high-consequence areas
October 2000	OPS issues the final rule
Beginning October 2000	OPS hires and trains additional staff to review companies' integrity management programs
December 2000	OPS completes the final rule on the definition of areas unusually sensitive to environmental damage and makes mapping information available to pipeline companies on the Internet
September 2001	Pipeline companies complete plans for assessing the condition of pipelines
September 2004	Individual companies' assessments are 50 percent complete
September 2007	Assessments are 100 percent complete

Source: GAO's analysis of OPS' data.

¹⁵OPS issued a proposed rule on the definition of areas unusually sensitive to environmental damage on Dec. 30, 1999. Comments on the proposed rule are due by June 27, 2000.

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APPENDIX A TO PART 192—
INCORPORATED BY REFERENCE

I. List of Organizations and Addresses

- A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.
- B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.
- C. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.
- D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.
- E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.
- F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NW., Vienna, VA 22180.
- G. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. 9101, Quincy, MA 02269-9101.

II. Documents Incorporated by Reference (Numbers in Parentheses Indicate Applicable Editions)

- A. American Gas Association (AGA):
 - (1). AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 22, 1989).
- B. American Petroleum Institute (API):
 - (1) API Specification 5L "Specification for Line Pipe (41st edition, 1995).
 - (2). API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe" (4th edition, 1990).
 - (3) API Specification 6D "Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)" (21st edition, 1994).
 - (4) API Standard 1104 "Welding of Pipelines and Related Facilities" (18th edition, 1994).
- C. American Society for Testing and Materials (ASTM):
 - (1) ASTM Designation: A 53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (A53-96).
 - (2) ASTM Designation A 106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-96).
 - (3) ASTM Designation: A 333/A 333M "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (A 333/A 333M-94).
 - (4) ASTM Designation: A 372/A 372M "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A 372/A 372M-95).

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- (5) ASTM Designation: A 381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems (A 381-93).
- (6) ASTM Designation: A 671 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A 671-94).
- (7) ASTM Designation: A 672 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (A 672-94).
- (8) ASTM Designation A 691 "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (A 691-93).
- (9) ASTM Designation D638 "Standard Test Method for Tensile Properties of Plastics" (D638-96).
- (10) ASTM Designation D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings" (D 2513-87 edition for §192.63(a)(1), otherwise D 2513-96a).
- (11) ASTM Designation D 2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D 2517-94).
- (12) ASTM Designation: F1055 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (F1055-95).
- D. The American Society of Mechanical Engineers (ASME):
 - (1) ASME/ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (1989).
 - (2) ASME/ANSI B16.5 "Pipe Flanges and Flanged Fittings" (1988 with October 1988 Errata and ASME/ANSI B16.5a-1992 Addenda).
 - (3) ASME/ANSI B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).
 - (4) ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems" (1995).
 - (5) ASME Boiler and Pressure Vessel Code, Section I "Power Boilers" (1995 edition with 1995 Addenda).
 - (6) ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 "Pressure Vessels" (1995 edition with 1995 Addenda).
 - (7) ASME Boiler and Pressure Vessel Code, Section VIII, Division 2 "Pressure Vessels: Alternative Rules" (1995 edition with 1995 Addenda).
 - (8) ASME Boiler and Pressure Vessel Code, Section IX "Welding and Brazing Qualifications" (1995 edition with 1995 Addenda).
- E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):
 - 1. MSS SP44-96 "Steel Pipe Line Flanges" (includes 1996 errata) (1996).
 - 2. [Reserved]
- F. National Fire Protection Association (NFPA):

EXHIBIT A - 7

CHAPTER I

SCOPE AND DEFINITIONS

400 GENERAL STATEMENTS

(a) This Liquid Transportation Systems Code is one of several sections of the ASME Code for Pressure Piping, B31. This Section is published as a separate document for convenience. This Code applies to hydrocarbons, liquid petroleum gas, anhydrous ammonia, alcohols, and carbon dioxide. Throughout this Code these systems will be referred to as Liquid Pipeline Systems.

(b) The requirements of this Code are adequate for safety under conditions normally encountered in the operation of liquid pipeline systems. Requirements for all abnormal or unusual conditions are not specifically provided for, nor are all details of engineering and construction prescribed. All work performed within the Scope of this Code shall comply with the safety standards expressed or implied.

(c) The primary purpose of this Code is to establish requirements for safe design, construction, inspection, testing, operation, and maintenance of liquid pipeline systems for protection of the general public and operating company personnel as well as for reasonable protection of the piping system against vandalism and accidental damage by others and reasonable protection of the environment.

(d) This Code is concerned with employee safety to the extent that it is affected by basic design, quality of materials and workmanship, and requirements for construction, inspection, testing, operation, and maintenance of liquid pipeline systems. Existing industrial safety regulations pertaining to work areas, safe work practices, and safety devices are not intended to be supplanted by this Code.

(e) The designer is cautioned that the Code is not a design handbook. The Code does not do away with the need for the engineer or competent engineering judgment. The specific design requirements of the Code usually revolve around a simplified engineering approach to a subject. It is intended that a designer capable of applying more complete and rigorous analysis to special or unusual problems shall have latitude in

the development of such designs and the evaluation of complex or combined stresses. In such cases the designer is responsible for demonstrating the validity of his approach.

(f) This Code shall not be retroactive or construed as applying to piping systems installed before date of issuance shown on document title page insofar as design, materials, construction, assembly, inspection, and testing are concerned. It is intended, however, that the provisions of this Code shall be applicable within 6 months after date of issuance to the relocation, replacement, and uprating or otherwise changing existing piping systems; and to the operation, maintenance, and corrosion control of new or existing piping systems. After Code revisions are approved by ASME and ANSI, they may be used by agreement between contracting parties beginning with the date of issuance. Revisions become mandatory or minimum requirements for new installations 6 months after date of issuance except for piping installations or components contracted for or under construction prior to the end of the 6 month period.

(g) The users of this Code are advised that in some areas legislation may establish governmental jurisdiction over the subject matter covered by this Code and are cautioned against making use of revisions that are less restrictive than former requirements without having assurance that they have been accepted by the proper authorities in the jurisdiction where the piping is to be installed. The Department of Transportation, United States of America, rules governing the transportation by pipeline in interstate and foreign commerce of petroleum, petroleum products, and liquids such as anhydrous ammonia or carbon dioxide are prescribed under Part 195 — Transportation of Hazardous Liquids by Pipeline, Title 49 — Transportation, Code of Federal Regulations.

400.1 Scope

400.1.1 This Code prescribes requirements for the design, materials, construction, assembly, inspection, and testing of piping transporting liquids such as crude (98)

CHAPTER VII

OPERATION AND MAINTENANCE PROCEDURES

450 OPERATION AND MAINTENANCE PROCEDURES AFFECTING THE SAFETY OF LIQUID TRANSPORTATION PIPING SYSTEMS

450.1 General

(a) It is not possible to prescribe in this Code a detailed set of operating and maintenance procedures that will encompass all cases. It is possible, however, for each operating company to develop operating and maintenance procedures based on the provisions of this Code, and the company's experience and knowledge of its facilities and conditions under which they are operated, which will be adequate from the standpoint of public safety.

(b) The methods and procedures set forth herein serve as a general guide, but do not relieve the individual or operating company from the responsibility for prudent action that current particular circumstances make advisable.

(c) It must be recognized that local conditions (such as the effects of temperature, characteristics of the line contents, and topography) will have considerable bearing on the approach to any particular maintenance and repair job.

(d) Suitable safety equipment shall be available for personnel use at all work areas and operating facilities where liquid anhydrous ammonia is transported. Such safety equipment shall include at least the following:

- (1) full face gas mask with anhydrous ammonia refill canisters;
- (2) independently supplied air mask;
- (3) tight-fitting goggles or full face shield;
- (4) protective gloves;
- (5) protective boots;
- (6) protective slicker and/or protective pants and jacket;
- (7) easily accessible shower and/or at least 50 gal (190 liters) of clean water in an open top container.

Personnel shall be instructed in effective use of masks and limited shelf life of refill canisters. Protective

clothing shall be of rubber fabric or other ammonia impervious material.

450.2 Operation and Maintenance Plans and Procedures

Each operating company having a transportation piping system within the scope of this Code shall:

(a) have written detailed plans and training programs for employees covering operating and maintenance procedures for the transportation piping system during normal operations and maintenance in accordance with the purpose of this Code; essential features recommended for inclusion in the plans for specific portions of the system are given in paras. 451 and 452.

(b) have a plan for external and internal corrosion control of new and existing piping systems, including requirements and procedures prescribed in para. 453 and Chapter VIII;

(c) have a written Emergency Plan as indicated in para. 454 for implementation in the event of system failures, accidents, or other emergencies; train appropriate operating and maintenance employees with regard to applicable portions of the plan, and establish liaison with appropriate public officials with respect to the plan;

(d) have a plan for reviewing changes in conditions affecting the integrity and safety of the piping system, including provisions for periodic patrolling and reporting of construction activity and changes in conditions, especially in industrial, commercial, and residential areas and at river, railroad, and highway crossings, in order to consider the possibility of providing additional protection to prevent damage to the pipeline in accordance with para. 402.1;

(e) establish liaison with local authorities who issue construction permits in urban areas to prevent accidents caused by excavators;

(f) establish procedures to analyze all failures and accidents for the purpose of determining the cause and to minimize the possibility of recurrence;

(g) maintain necessary maps and records to properly administer the plans and procedures, including records listed in para. 455;

401.6.1–402.2.5

ASME B31.4-1998 Edition

401.6.1 Live Loads. Live loads include the weight of the liquid transported and any other extraneous materials such as ice or snow that adhere to the pipe. The impact of wind, waves, and currents are also considered live loads.

401.6.2 Dead Loads. Dead loads include the weight of the pipe, components, coating, backfill, and unsupported attachments to the piping.

401.7 Thermal Expansion and Contraction Loads

Provisions shall be made for the effects of thermal expansion and contraction in all piping systems.

401.8 Relative Movement of Connected Components

The effect of relative movement of connected components shall be taken into account in design of piping and pipe supporting elements.

402 DESIGN CRITERIA**(98) 402.1 General**

Paragraph 402 pertains to ratings, stress criteria, design allowances, and minimum design values, and formulates the permissible variations to these factors used in the design of piping systems within the scope of this Code.

The design requirements of this Code are adequate for public safety under conditions usually encountered in piping systems within the scope of this Code, including lines within villages, towns, cities, and industrial areas. However, the design engineer shall provide reasonable protection to prevent damage to the pipeline from unusual external conditions which may be encountered in river crossings, inland coastal water areas, bridges, areas of heavy traffic, long self-supported spans, unstable ground, vibration, weight of special attachments, or forces resulting from abnormal thermal conditions. Some of the protective measures which the design engineer may provide are encasing with steel pipe of larger diameter, adding concrete protective coating, increasing the wall thickness, lowering the line to a greater depth, or indicating the presence of the line with additional markers.

402.2 Pressure-Temperature Ratings for Piping Components

402.2.1 Components Having Specific Ratings. Within the metal temperature limits of -20°F (-30°C) to 250°F (120°C), pressure ratings for components shall

conform to those stated for 100°F (40°C) in material standards listed in Table 423.1. The nonmetallic trim, packing, seals, and gaskets shall be made of materials which are not injuriously affected by the fluid in the piping system and shall be capable of withstanding the pressures and temperatures to which they will be subjected in service. Low temperatures due to pressure reduction situations, such as blow downs and other events, shall be considered when designing carbon dioxide pipelines.

402.2.2 Ratings — Components Not Having Specific Ratings. Piping components not having established pressure ratings may be qualified for use as specified in paras. 404.7 and 423.1(b).

402.2.3 Normal Operating Conditions. For normal operation the maximum steady state operating pressure shall not exceed the internal design pressure and pressure ratings for the components used.

402.2.4 Ratings — Allowance for Variations From Normal Operations. Surge pressures in a liquid pipeline are produced by a change in the velocity of the moving stream that results from shutting down of a pump station or pumping unit, closing of a valve, or blockage of the moving stream.

Surge pressure attenuates (decreases in intensity) as it moves away from its point of origin.

Surge calculations shall be made, and adequate controls and protective equipment shall be provided, so that the level of pressure rise due to surges and other variations from normal operations shall not exceed the internal design pressure at any point in the piping system and equipment by more than 10%.

402.2.5 Ratings — Considerations for Different Pressure Conditions. When two lines that operate at different pressure conditions are connected, the valve segregating the two lines shall be rated for the more severe service condition. When a line is connected to a piece of equipment which operates at a higher pressure condition than that of the line, the valve segregating the line from the equipment shall be rated for at least the operating condition of the equipment. The piping between the more severe conditions and the valve shall be designed to withstand the operating conditions of the equipment or piping to which it is connected.

§ 192.607

49 CFR Ch. I (10-1-99 Edition)

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting re-

quirements of § 191.23 of this subchapter.

(e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§ 192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994, as amended by Amdt. 192-71A, 60 FR 14381, Mar. 17, 1995]

§ 192.607 [Reserved]**§ 192.609 Change in class location: Required study.**

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be ascertained from available records;

(d) The operating and maintenance history of the segment;

(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the

§ 195.307

49 CFR Ch. I (10-1-99 Edition)

§ 195.307 Pressure testing above-ground breakout tanks.

(a) For aboveground breakout tanks built to API Specification 12F and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of API Specification 12F.

(b) For aboveground breakout tanks built to API Standard 620 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.18 of API Standard 620.

(c) For aboveground breakout tanks built to API Standard 650 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.3 of API Standard 650.

(d) For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C that are returned to service after October 2, 2000, the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 10.3 of API Standard 653.

(e) For aboveground breakout tanks built to API Standard 2510 and first placed in service after October 2, 2000, pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.

[Amdt. 195-66, 64 FR 15936, Apr. 2, 1999]

§ 195.308 Testing of tie-ins.

Pipe associated with tie-ins must be pressure tested, either with the section to be tied in or separately.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by 195-51, 59 FR 29385, June 7, 1994]

§ 195.310 Records.

(a) A record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.

(b) The record required by paragraph (a) of this section must include:

- (1) The pressure recording charts;
- (2) Test instrument calibration data;
- (3) The name of the operator, the name of the person responsible for

making the test, and the name of the test company used, if any;

(4) The date and time of the test;

(5) The minimum test pressure;

(6) The test medium;

(7) A description of the facility tested and the test apparatus;

(8) An explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts; and

(9) Where elevation differences in the section under test exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

[Amdt. 195-34, 50 FR 34474, Aug. 26, 1985, as amended by Amdt. 195-51, 59 FR 29385, June 7, 1994; Amdt. 195-63, 63 FR 37506, July 13, 1998]

Subpart F—Operation and Maintenance**§ 195.400 Scope.**

This subpart prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe.

§ 195.401 General requirements.

(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under § 195.402(a) of this subpart.

(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(c) Except as provided in § 195.5, no operator may operate any part of any of the following pipelines unless it was designed and constructed as required by this part:

(1) An interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid.

(2) An interstate offshore gathering line, other than a low-stress pipeline, on which construction was begun after

Research and Special Programs Administration, DOT

§ 191.23

Transportation Form RSPA 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) The annual report required by paragraph (a) of this section need not be submitted with respect to LNG facilities.

[Amdt. 191-5, 49 FR 18961, May 3, 1984]

§ 191.19 Report forms.

Copies of the prescribed report forms are available without charge upon request from the address given in § 191.7. Additional copies in this prescribed format may be reproduced and used if in the same size and kind of paper. In addition, the information required by these forms may be submitted by any other means that is acceptable to the Administrator.

[Amdt. 191-10, 61 FR 18516, Apr. 26, 1996]

§ 191.21 OMB control number assigned to information collection.

This section displays the control number assigned by the Office of Management and Budget (OMB) to the gas pipeline information collection requirements of the Office of Pipeline Safety pursuant to the Paperwork Reduction Act of 1980, Public Law 96-511. It is the intent of this section to comply with the requirements of section 3507(f) of the Paperwork Reduction Act which requires that agencies display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB CONTROL NUMBER 2137-0522
(APPROVED THROUGH MARCH 31, 1986)

Section of 49 CFR part 191 where identified	Form No.
191.5	Telephonic.
191.9	RSPA 7100.1
191.11	RSPA 7100.1-1
191.15	RSPA 7100.2
191.17	RSPA 7100.2-1.

[Amdt. 191-5, 49 FR 18961, May 3, 1984]

§ 191.23 Reporting safety-related conditions.

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with § 191.25 the existence of any of the following safety-

ty-related conditions involving facilities in service:

(1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.

(3) Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.

(4) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength.

(5) Any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices.

(6) A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency.

(7) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

(8) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes gas or LNG.

(b) A report is not required for any safety-related condition that—

(1) Exists on a master meter system or a customer-owned service line;

EXHIBIT E

Date: Thursday, May 10, 2001 2:04:06 PM
From: Lloyd.Ulrich@rspa.dot.gov
Subj: Inquiry
To: ezsafeoil@aol.com

You asked:

For a pipeline laid in 1942 at about 14" of cover, if the line is now both (1) uprated in operating pressure, and (2) converted to Hazardous Liquid / LPG service from crude oil service (i.e., from Part 194 to Part 195 service),
can the line still be operated at the original depth?

My technical answer is "yes." If you want an official, legal answer, write to Richard Hurliaux, Manager, Regulations, Office of Pipeline Safety (DPS-12), Department of Transportation, 400 7th Street S.W., Washington, DC 20590.

The pipeline was constructed in 1942 which was before the safety regulation over hazardous liquid pipelines in 49 CFR part 195 went into effect (1970) so

the pipeline is "grandfather." The regulation on cover is a construction rule, not an operating rule, so it only applies at the time of construction, which in this case was before the regulations were in effect. However, the

pipeline is subject to the operating rules if operated above 20% of SMYS - YES ①

and may be subject to the operating rules if operated at or below 20% of SMYS and one rule, section 195.401, states "Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time" Depending on the location of the pipeline, 14" cover may constitute a "condition that could adversely affect the safe operation" since the cover for a new pipeline buried where there is normal excavation (as opposed to rock excavation) is

5/11/01

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Page 1

MUNIZ Genl



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Marking Liquid Petroleum Pipeline Facilities

API RECOMMENDED PRACTICE 1109
SECOND EDITION, APRIL 1993



American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005



1.4 Conflicting Requirements

If any provisions of this recommended practice present a direct or implied conflict with any statutory regulation, the regulation shall govern. However, if this recommended practice's recommendations are more stringent than the requirements of the regulation, then the recommendations presented herein should be considered.

1.5 Referenced Publications

The most recent editions of the following standards, codes, and specifications are cited in this publication:

ASME²

B31.4 *Liquid Transportation Systems for Hydrocarbons, Liquid, Petroleum Gas, Anhydrous Ammonia, and Alcohols*

RSPA³

49 *Code of Federal Regulations* Part 195 ("Transportation of Hazardous Liquids by Pipeline")

²American Society of Mechanical Engineers, 345 East 47th Street, New York, New York 10017.

³Research and Special Programs Administration, U. S. Department of Transportation. The *Code of Federal Regulations* is available from the U.S. Government Printing Office, Washington, D.C. 20402.

SECTION 2—BURIED PIPELINE FACILITY MARKING PRACTICE

2.1 General Description, Use, and Placement

2.1.1 Permanent pipeline facility markers and signs are used to convey information relative to the following:

- a. The presence of a liquid petroleum pipeline facility.
- b. A potential hazard.
- c. The contacting of the pipeline operator for any of the following:
 1. The precise location of the buried pipeline.
 2. An authorization to cross or occupy the pipeline right-of-way.
 3. Emergencies.

Numerous methods can be used to indicate the presence of buried pipeline. The recommended method is aboveground markers and signs.

2.1.2 In some instances, the successful completion of various day-to-day activities requires a pipeline operator to readily locate buried pipelines. In these instances, consideration should be given to installing markers or signs at fence lines, property lines, right-of-way boundaries, water crossings, and aboveground crossings.

2.1.3 When line markers are installed, locations should be chosen to meet the requirements of 49 *Code of Federal Regulations* Part 195.

2.1.4 Examples of cross country right-of-way markings are shown in Figures 1 and 2.

2.2 Types of Posts

Posts may be made of any materials that will ensure adequate strength, stiffness, visibility, and durability. To main-

tain structural integrity and appearance, some post materials require surface protection against above- and belowground corrosion or weathering. A proven coating system that provides a suitable finish and nonfading color should be selected for this purpose. The following criteria should be applied in the selection of marker posts:

- a. Metal pipe posts should be straight, sound, and have a nominal diameter of 2 inches or larger.
- b. Metal structures designed for use as posts may be used.
- c. Straight posts made from debarked trees and treated with a pressure-applied chemical preservative may be used. The smaller end of such posts should not be less than 8 inches in diameter. Wood posts are not recommended where brush or grass fires may be expected.
- d. Square precast reinforced-concrete posts having a minimum cross-sectional area of 16 square inches may be used. Special conditions, such as spalling during freeze and thaw cycles, should be considered when specifying material for these types of posts.
- e. Posts made of Polyvinyl-chloride (PVC), Polyethylene, and fiberglass may be used. Materials used, however, should be resistant to ultraviolet exposure and suited to the environment where installed (see Figure 3).
- f. Other materials are acceptable provided they meet the general criteria discussed above. Materials used should be resistant to ultraviolet exposure and suited to the environment where installed.

2.3 Line Markers

2.3.1 Part 195 of 49 *Code of Federal Regulations* requires that certain information be presented on line markers in lettering of a certain size and stroke. The regulations further require that line markers be placed over all buried pipeline at

each public road crossing, at each railroad crossing, and in sufficient numbers along the remainder of each buried pipeline so that its location is accurately known.

2.3.2 The line marker's message should be presented on strong, durable material finished to resist the effects of exposure and vandalism. The message should state at least the following: "WARNING," followed by the words "PETROLEUM [or the name of the liquid petroleum transported] PIPELINE." The lettering should be at least 1 inch high with an approximate stroke of $\frac{1}{4}$ inch on a background of sharply contrasting color. It should also contain the name of the pipeline operator with a telephone number, including an area code, where the pipeline operator can be reached at all times.

2.3.3 The line markers depicted in Figures 3 and 4 are appropriate for general use by the liquid petroleum pipeline industry. The dimensions, wording, colors, and configuration shown on the figures are recommended for good visibility. The size and style of the lettering identifying the pipeline operator are optional. A trademark or other identifying symbol may appear as part of the pipeline operator's identification.

2.3.4 Caution should be used when installing a line marker anywhere other than directly over or in proximity to the buried pipeline to avoid any possible misinterpretation as to where the actual pipeline is located.

2.4 Other Markers

2.4.1 The pipeline operator may use markers and signs other than line markers to aid in determining the locations of the pipeline. Examples of such markers are listed below:

- a. Aerial patrol markers.
- b. Prominently colored posts at fences, and right-of-way limits of roads and railroads.
- c. Markers at banks of water crossings.
- d. Stencilled markings on the surface of pavements (see Figure 5).
- e. Buried tape.
- f. Casing vents.
- g. Cathodic protection test stations.
- h. Any other kind of marker the operator recognizes as necessary in such locations.

2.4.2 When signs are used to identify pipeline crossings at navigable waterways they should contain the words "DO NOT ANCHOR OR DREDGE." The sign's lettering should not be less than 12 inches high, with an approximate stroke of $\frac{1}{4}$ inch on a background of sharply contrasting color. This lettering is in addition to the information recommended in 2.3.2. Because government agencies or authorities may share jurisdiction over certain navigable waterways, the specifications for and placement of markers for a particular

waterway should satisfy those joint requirements. Many agencies accept or adopt the requirements of the United States Army Corps of Engineers. Figure 6 shows an appropriate navigable waterway sign.

2.4.3 The pipeline operator may elect to place markers of special design in particular locations where current or projected activities of others may warrant their installation. Consideration should be given to whether the markers are for temporary or permanent service.

2.4.4 Aerial patrol markers should be used along the routes of pipelines that are patrolled by aircraft. Figure 7 is an example of a typical aerial marker. Aerial markers should be placed at locations where they can easily be identified from the air.

2.5 Installation

2.5.1 Typically, the message portion of any marker is attached to, or is an integral part of, a post of the type described in 2.2. Consideration should also be given to attaching the message portion of any marker to pipeline vent pipes, fences, fence posts, or other existing posts to reduce the overall clutter at the site, provided that in the case of line markers, the requirements noted in 2.3.1 are met.

2.5.2 The following factors should be considered in determining the depth to bury marker posts:

- a. Post material.
- b. Method of installation.
- c. Type of soil.
- d. State of soil consolidation.
- e. Depth of frost line and propensity of soil to heave.
- f. Size, shape, height, and weight of the pipeline marker assembly.
- g. Exposure to external forces such as wind, high water, currents, large livestock, or wildlife.
- h. Depth of pipeline to be marked.

2.5.3 Aboveground markers should be sufficiently elevated to allow them to be clearly viewed from a distance, and to allow them to remain visible above normal vegetation or snow accumulation. A minimum height of 4 feet above grade is recommended.

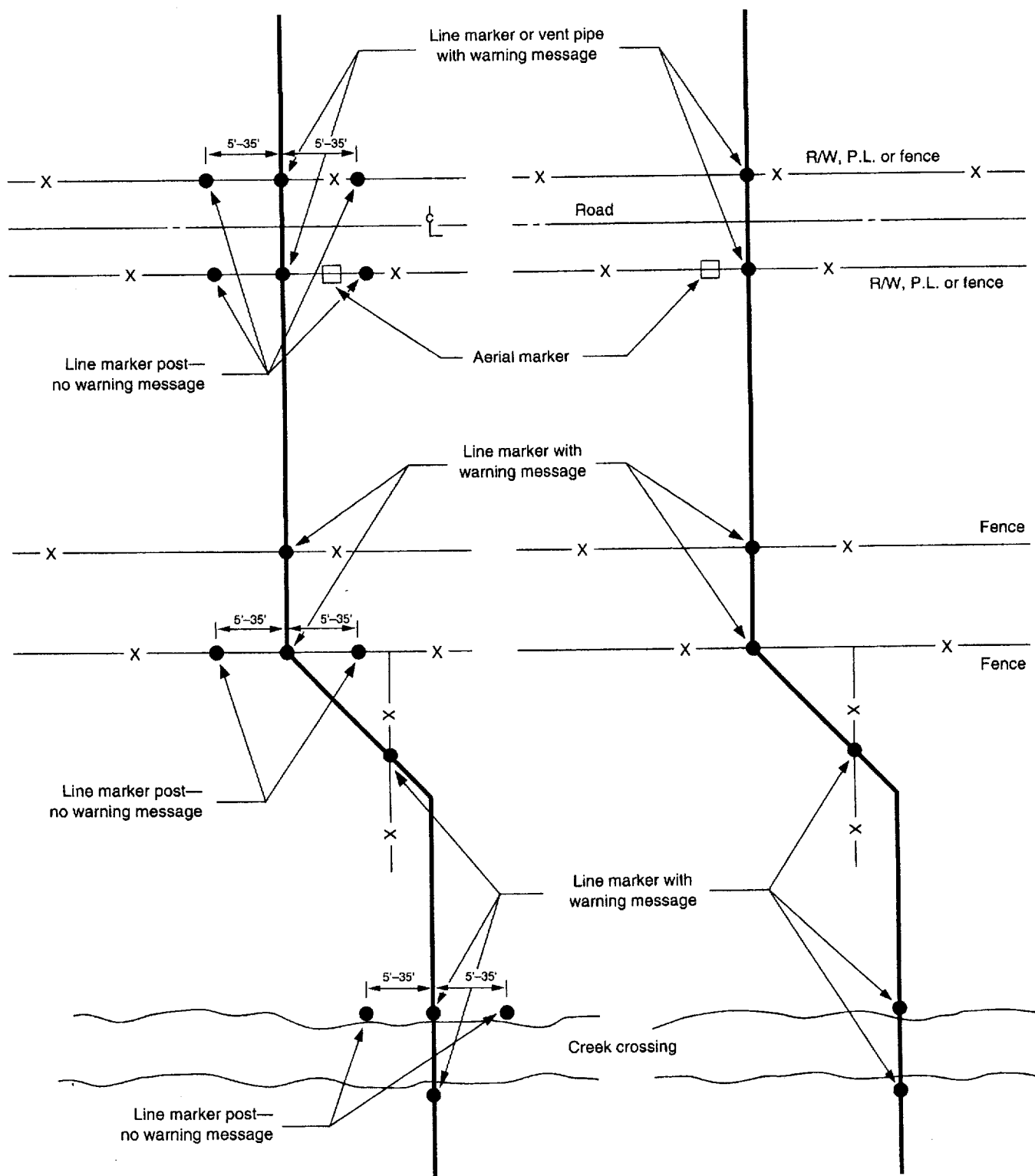
2.5.4 When necessary, the post holes should be backfilled with concrete.

2.5.5 When installing posts, caution should be exercised to avoid any other underground structures.

2.5.6 The bottom of posts may be modified or fitted with transverse members to inhibit unauthorized removal or ejection by frost heaving.

MARKING LIQUID PETROLEUM PIPELINE FACILITIES

5



Notes:

1. R/W= right-of-way
2. P.L.= property line

Figure 1—Examples of Cross Country Right-of-Way Markings

EXHIBIT G

SEE FOLLOWING COVER PAGE

OF REPORT

THAT CONTAINS LEAK INFORMATION

**(THIS IS ONE EXAMPLE OF LEAK, SPILL, AND
INCIDENT INFORMATION ON THE SUBJECT PIPELINES)**



Rimkus Consulting Group, Inc.
Eight Greenway Plaza, Suite 500
Houston, Texas 77046
(713) 621-3550 Telephone
(713) 623-4357 Facsimile

EXPERT OPINION OF

MR. THOMAS J. KOCUREK, P.E.
MR. ERNEST M. HONIG, JR. PHD.
MR. PHILIP R. WATTERS, M.B.A., P.E.

Style: United States and the State of Texas v. Koch Industries, Inc., et al
Court: United States District Court for the Southern District Of Texas,
Houston Division
Date: January 4, 1999

SUMMARY OF OPINION

Rimkus Consulting Group, Inc. was retained by the United States Department of Justice (D.O.J.) and the State of Texas to examine the causes of each spill and to determine whether Koch acted prudently in the conduct of its pipeline activities. The purpose of our study and examination was to determine the following:

- Whether Koch violated any of the provisions of the D.O.T. 49CFR195 regulations.
- Whether Koch violated any of the provisions of the American Society of Mechanical Engineers (ASME) B31.4 codes.
- Whether Koch violated any of the provisions of the National Association of Corrosion Engineers (N.A.C.E.) standards.

RISK MANAGEMENT WITHIN THE LIQUID PIPELINE INDUSTRY

A Report from
**The Joint Government / Industry
Risk Assessment Quality Team**

Sponsored by
**The Office of Pipeline Safety (OPS)
and
The American Petroleum Institute (API)**

**Final Report
June 20, 1995**

Assurance Of Hazardous Liquid Pipeline System Integrity

Manufacturing, Distribution and Marketing Department

**API RECOMMENDED PRACTICE 1129
FIRST EDITION, AUGUST 1996**



27

UNITED STATES OF AMERICA
NATIONAL TRANSPORTATION SAFETY BOARD
 WASHINGTON, D.C.

CERTIFICATE OF TRUE COPY

I HEREBY CERTIFY that the attached is a true copy of the original on file in the Analysis and Data Division, National Transportation Safety Board, which original comprises the material available from the NTSB public reference file concerning the pipeline accident at Lively, Texas on August 24, 1996, NTSB/PAR-98/02/SUM, and that I have legal custody of the record involved.



Signed and dated at Washington, DC

this 11th day of August 19 99

by Susan Stevenson
 (Signature)

Archives Technician
 (Title)

I HEREBY CERTIFY that Susan Stevenson who signed the foregoing certificate is now, and was, at the time of signing the Archives Technician, Public Inquiries Branch, Analysis and Data Division, National Transportation Safety Board, that she has legal custody of the record involved, and that full faith and credit should be given her certificate as such.

IN WITNESS WHEREOF, I have hereunto subscribed

my name and caused the seal of the National

Transportation Safety Board to be affixed this

11th day of August 19 99

Michael S. Dwyer
 (Signature)

Records Management Officer/Analysis and Data Division
 (Title)

National Transportation Safety Board

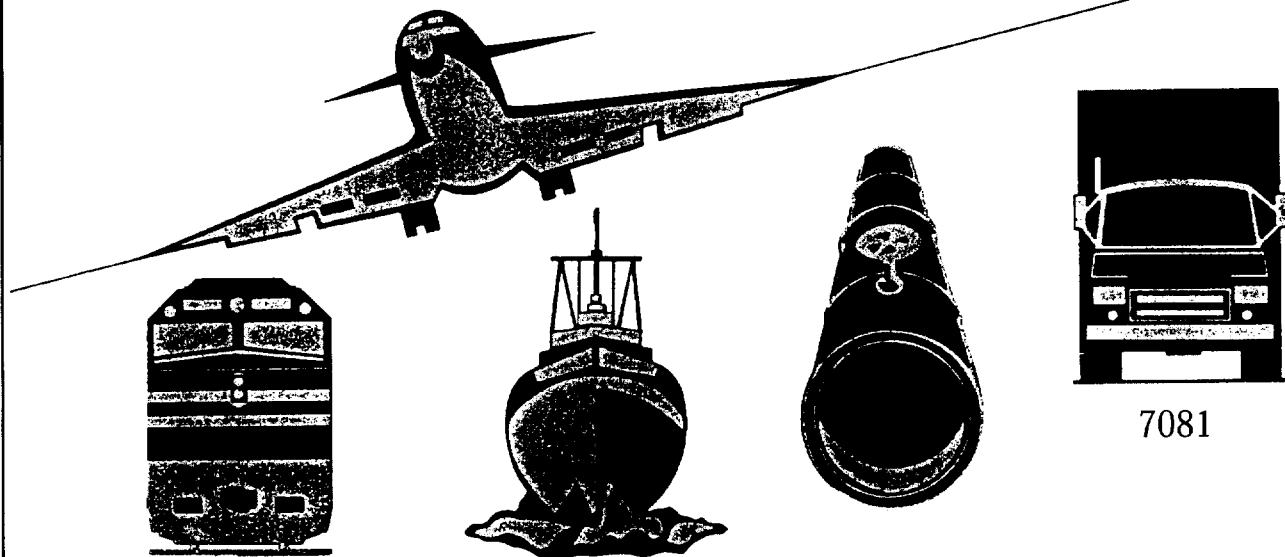
PB98-916503
NTSB/PAR-98/02/SUM

NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT SUMMARY REPORT

PIPELINE RUPTURE, LIQUID BUTANE RELEASE,
AND FIRE
LIVELY, TEXAS
AUGUST 24, 1996



Abstract: This report explains the August 24, 1996, rupture of a steel pipeline operated by Koch Pipeline Company, LP (Koch), which sent a butane vapor cloud into the surrounding residential area. The butane vapor ignited as two residents in a pickup truck drove into the cloud. The occupants of the truck died from thermal injuries. About 25 families were evacuated from the area. Damages related to the accident exceeded \$217,000.

From its investigation of this accident, the Safety Board identified safety issues in the following areas: the adequacy of Koch's corrosion inspection and mitigation actions, and the effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

As a result of its investigation of this accident, the Safety Board issued recommendations to the Research and Special Programs Administration, Koch, and NACE International.

The National Transportation Safety Board is an independent Federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable cause of accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The Safety Board makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

Recent publications are available in their entirety on the Web at <http://www.nts.gov/>. Other information about available publications may be obtained by contacting:

National Transportation Safety Board
Public Inquiries section, RE-51
490 L'Enfant Plaza East, S.W.
Washington, D.C. 20594
(202) 314-6551

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National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161
(703) 605-6000

PIPELINE ACCIDENT SUMMARY REPORT

**Pipeline Rupture, Liquid Butane Release, and Fire
Lively, Texas
August 24, 1996**

**NTSB/PAR-98/02/SUM
PB98-916503
Notation 7081
Adopted: November 6, 1998**



**National Transportation Safety Board
490 L'Enfant Plaza, S.W.
Washington, D.C. 20594**

Executive Summary

On Saturday, August 24, 1996, about 3:26 p.m., an 8-inch-diameter steel LPG (liquefied petroleum gas) pipeline transporting liquid butane, operated by Koch Pipeline Company, LP (Koch), ruptured near Lively, Texas, sending a butane vapor cloud into a surrounding residential area. The rupture occurred under a roadway in the Oak Circle Estates subdivision.

The butane vapor ignited as two residents in a pickup truck drove into the vapor cloud. According to the sheriff's report, they were on their way to a neighbor's house to report the release to 911. The two people died at the accident site from thermal injuries. No other injuries were reported at that time; however, about 25 families were evacuated from Oak Circle Estates.

Koch estimated its direct pipeline losses, including the loss of product from the line, to be about \$217,000. Other property losses included damage to the roadway under which the rupture occurred and damage to a pickup truck, a mobile home, several outbuildings, and adjacent woodlands.

The National Transportation Safety Board determines that the probable cause of this accident was the failure of Koch to adequately protect its pipeline from corrosion. The major safety issues identified by this investigation are as follows:

- Adequacy of Koch's corrosion inspection and mitigation actions, and
- Effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

As a result of its investigation of this accident, the Safety Board issued recommendations to the Research and Special Programs Administration, Koch, and NACE International.

Factual Information

Accident Narrative

On Saturday, August 24, 1996, about 3:26 p.m.,¹ an 8-inch-diameter steel LPG (liquefied petroleum gas) pipeline transporting liquid butane,² operated by Koch Pipeline Company, LP (Koch),³ ruptured near Lively, Texas, sending a butane vapor cloud into a surrounding residential area. The rupture occurred under a roadway in the Oak Circle Estates subdivision (figure 1).

The butane vapor ignited (figure 2) as two residents in a pickup truck drove into the vapor cloud. According to the sheriff's report, they were on their way to a neighbor's house to report the release to 911. The two people died at the accident site from thermal injuries. No other injuries were reported at that time; however, about 25 families were evacuated from Oak Circle Estates.

Koch estimated its direct pipeline losses, including the loss of product from the line, to be about \$217,000. Other property losses included damage to the roadway under which the rupture occurred and damage to a pickup truck, a mobile home, several outbuildings, and adjacent woodlands.

Preaccident Events

At 2:05 p.m. on the day of the accident, Koch's Cleveland pump station (see figure 3 for station locations) experienced an automated shutdown due to the activation of a hydrocarbon vapor detection alarm in the station. A technician who was called out to check the station found no vapor or evidence of a leak at the station. Cleveland pump station is about 200 pipeline miles downstream of the accident site, and this shutdown reduced flow through the pipeline. Corsicana station, the first pump station upstream of Cleveland station, automatically shut down at 3:05 p.m. because the rising pipeline pressure activated a high-discharge pressure alarm.⁴ The Corsicana pump shutdown created a

¹ Times given in this report are central daylight time.

² Liquid butane is a highly volatile liquid (HVL) petroleum product that vaporizes at atmospheric pressure and room temperature. Upon release, the liquid vaporizes into a highly flammable white or nearly transparent fog-like cloud. Because the vapor is heavier than air, it stays close to the ground and settles into low-lying areas. While the liquid is not odorized, it has a faint but noticeable petroleum-like smell. Observation of a vapor or a fog-like cloud is typically how butane is detected in the atmosphere near a release.

³ Koch Pipeline Company, LP (Limited Partnership), is owned by Koch Industries, Inc.

⁴ A high-discharge pressure alarm is triggered when the station discharge pressure to the pipeline rises above the set-point limit; the instrument's switch will shut down the station.

Factual Information

2

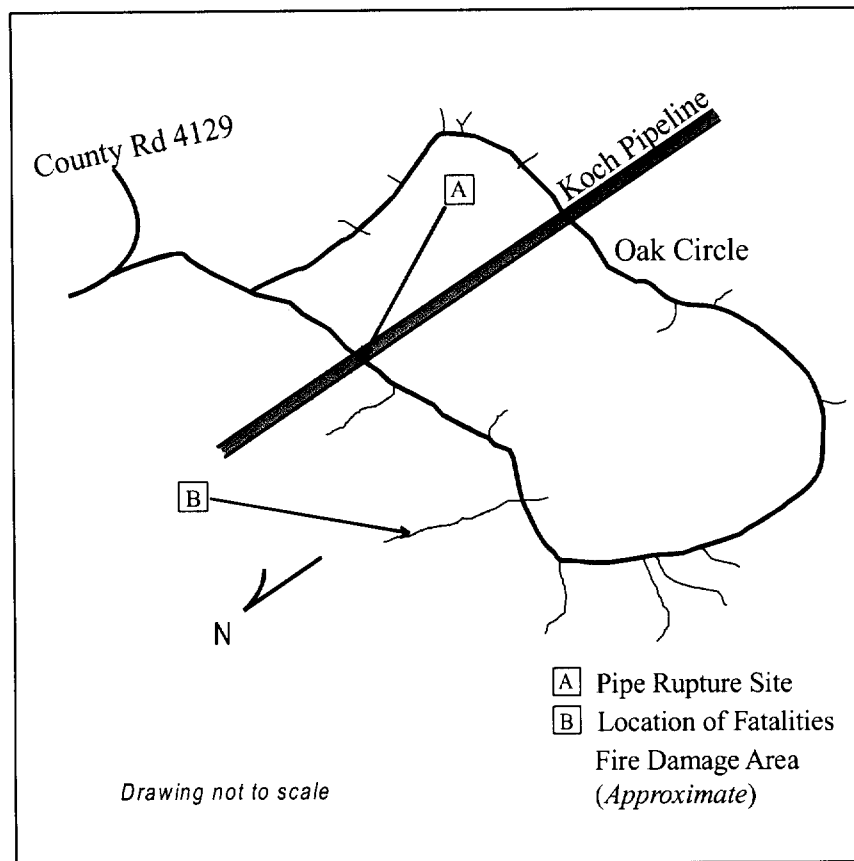
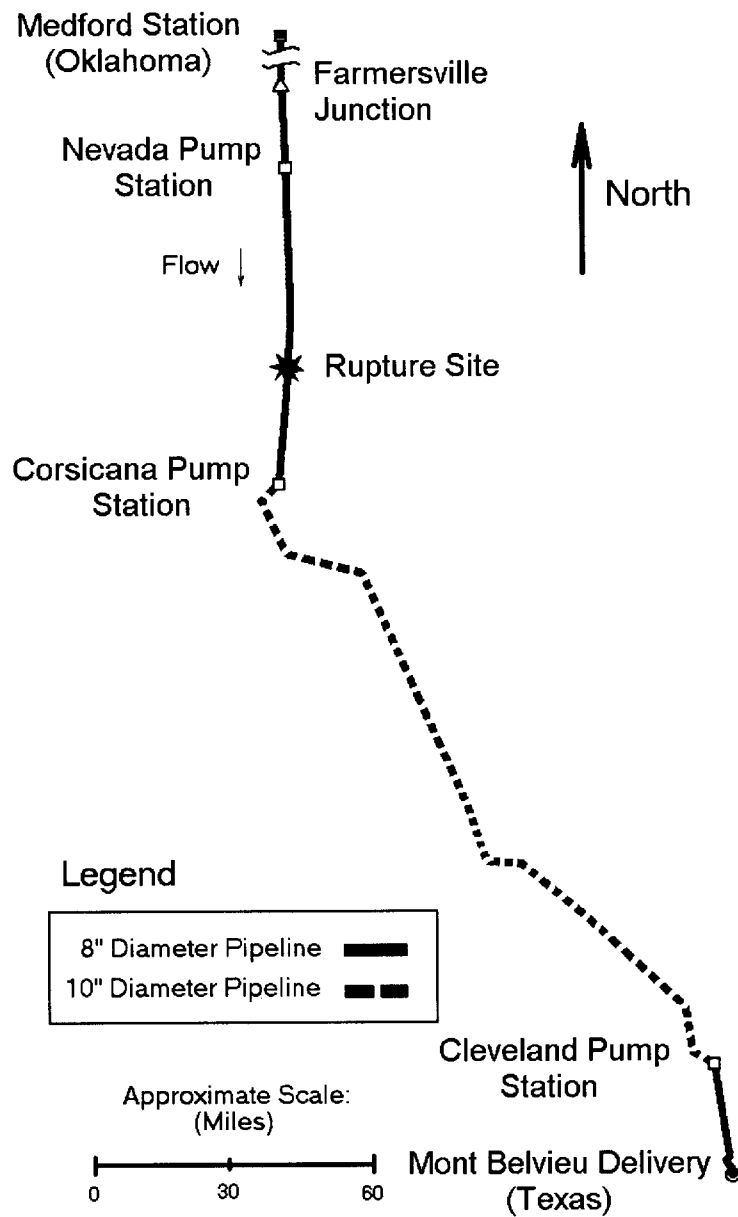


Figure 1. Sketch showing area of butane vapor dispersement and corresponding fire



Figure 2. Accident site before the butane fire was extinguished



**Figure 3. Koch Pipeline Company—
Medford, Oklahoma, to Mont Belvieu, Texas**

Factual Information**4**

pressure surge⁵ in the pipeline that traveled upstream to the previous station, Nevada pump station. The rupture occurred between Nevada and Corsicana pump stations.

The maximum operating pressure (MOP) established by Koch for this pipeline was 1,440 pounds per square inch, gauge (psig).⁶ After the accident, Koch calculated the highest surge pressure at Nevada pump station to be 1,448 psig based on pipeline pressure and flow conditions before the rupture. The pipeline discharge pressure was throttled to 1,438 psig by the pump station control valve, and the pump continued to operate. The highest surge pressure at the pipeline rupture location after the Corsicana station pump shut down was calculated by Koch to be 1,273 psig at 3:14 p.m.

Postaccident Events

At 3:29 p.m., Koch's supervisory control and data acquisition (SCADA) system generated a discharge pressure rate-of-change alarm⁷ at Nevada pump station. At 3:36 p.m., another rate-of-change alarm was generated at Nevada pump station, and the pipeline controller shut down the pump because of the unexplained pressure loss. At 3:39 p.m., Koch received a telephone call from an Oak Circle Estates resident reporting a pipeline leak near his home. Koch immediately began shutdown procedures for the entire pipeline, dispatched an employee to the accident site, and called the Kaufman County sheriff's department. During its call to the sheriff's department, Koch learned that the butane had ignited. The sheriff's department and 911 each received a call about the release at about the same time that Koch received its call.

Following the shutdown of its pump stations, Koch began to isolate the ruptured section of the pipeline by closing the manual block valves upstream (4:20 p.m.) and downstream (4:37 p.m.) of the rupture. At 5:25 p.m., Koch reported the release to the National Response Center. By 6:00 p.m. the next day, line-plugging equipment⁸ had been installed and used to isolate a section of pipeline about 100 yards on either side of the rupture. With the closing of the line-plugging equipment, the fuel was cut off and the fire extinguished within minutes. The pipeline remained shut down until March 1997.

⁵ A pressure surge is a transient or temporary increase in pressure caused by a change in flow conditions on a pipeline such as a valve closing or a pump shutting down.

⁶ The Federal pipeline safety regulation in 49 *Code of Federal Regulations* (CFR) Part 195.406(b) requires that the pressure in a pipeline during surges not exceed 110 percent of the MOP.

⁷ A rate-of-change alarm is generated when station discharge pressure decreases a preset amount within a specific time as previously determined by the pipeline operator.

⁸ Line-plugging equipment can be installed even when the pipeline contains product without exposing that product to the atmosphere.

Factual Information

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Investigation

The National Transportation Safety Board was notified of the accident on August 24, 1996, by the National Response Center. The Office of Pipeline Safety, Research and Special Programs Administration, conducted the on-scene investigation. Segments of the pipeline, including the ruptured pipe, were shipped to the Safety Board Materials Laboratory in Washington, D.C., for metallurgical examination.

Personnel and Toxicological Information

The pipeline controller, who had been on duty for about 8 1/2 hours when the accident occurred, had been employed with Koch for 6 1/2 years. About 2 hours after the accident, the controller was tested for drugs and alcohol; both test results were negative.

Pipeline Information

When the accident occurred, Koch's Sterling I pipeline system was transporting liquid butane from Medford, Oklahoma, to Mont Belvieu, Texas (about 570 miles). This pipeline system contains sections of 8- and 10-inch-diameter pipe.

The 10-inch-diameter portion of the pipeline between Corsicana and Cleveland pump stations (see figure 3 pipeline map) was constructed in 1929 and later purchased by Koch. In April 1995, Koch completed replacement of the original 1929 section with new 10-inch-diameter epoxy-coated pipe to improve this section's integrity.

The pipeline rupture occurred in the 70-mile section of 8-inch-diameter pipeline between Nevada and Corsicana pump stations. The ruptured line, originally constructed in 1981, was a nominal 8-inch outside diameter, American Petroleum Institute (API) Specification 5L, Grade X-46, 0.188-inch wall thickness, Electric Resistance Weld steel pipe. The pipe was externally field coated with spiral wrapped polyolefin tape to protect it from corrosion. In the early 1990s, the road for the housing development was constructed over the 8-inch-diameter pipeline at the accident site.

During construction of the 10-inch-diameter pipe in 1995, Koch shut down the pipeline from Farmersville Junction (north of Nevada pump station) to Cleveland pump station. Before moving LPG products again, the 8-inch-diameter section from Farmersville Junction to Corsicana pump station was hydrostatically pressure tested in two segments to confirm its integrity. Three failures were documented during the pressure testing. The northern segment failed two times: the first time due to external corrosion at 1,941 psig and the second time due to a longitudinal weld seam failure at 1,938 psig. The failure in the southern test segment, about 1.5 miles north of the accident site, occurred because of external corrosion. The pipeline pressure when the southern segment failed was 1,400 psig, which was less than the previously established maximum operating pressure of 1,440 psig.

Internal Pipeline Inspection

May 1995 Internal Inspection

In May 1995, after the three hydrostatic pressure test failures, Koch had an internal inspection performed to determine the pipeline's condition. An internal inspection tool (also known as a "smart pig") was run through the 8-inch-diameter pipeline to determine the condition of 46 miles of pipeline in the southern section. A metal-wall-loss inspection was performed using a low-resolution magnetic-flux-leakage (MFL) internal inspection tool. This inspection identified numerous sites of external corrosion for possible repair.

Actual corrosion pit depths were measured on pipe excavated for correlation digs and then compared with the log of corrosion indications from the May 1995 internal inspection. All of the pipe-wall-thickness loss indications were graded by the internal inspection tool company as being light (15 to 30 percent loss), moderate (> 30 and < 50 percent loss), or severe (\geq 50 percent loss). The log results were reported by individual pipe length⁹ and the grade of the maximum corrosion anomaly.

The May 1995 internal inspection log identified 62 moderately and 18 severely corroded pipe lengths. According to Koch, the company excavated all pipe lengths graded as having moderate or severe wall-thickness loss. Excavated pipe was either recoated, repaired, or replaced. Koch took action based on its determination of the effect of corrosion on remaining pipe strength and allowable operating pressure using ASME/ANSI B31G.¹⁰ The pipe that ruptured in 1996 was not excavated in 1995 because the associated pipe length was identified by the internal inspection tool as having light corrosion.

Comparisons of the wall-thickness measurements of the pipe lengths excavated during the repair digs with the inspection log results revealed few discrepancies. Koch's records from the repair digs indicate only three instances of a discrepancy between the inspection log and actual dig report measurement. In each case, the internal inspection tool predicted a pipe-wall-thickness loss greater than was actually measured.

The minimum hydrostatic test pressure required by pipeline safety regulations is 125 percent of the MOP. In this case, the MOP was 1,440 psig, making the minimum test pressure for the line 1,800 psig. After pipeline repairs based on data from the internal inspection had been completed, the line was hydrostatically tested without failure to 1,855 psig on August 18, 1995, and subsequently returned to service.

⁹ In this pipeline, the individual 8-inch-diameter pipe lengths were about 59 feet.

¹⁰ *Manual: Determining Remaining Strength of Corroded Pipelines: Supplement to B31 Code-Pressure Piping (B31G)*. American Society of Mechanical Engineers/American National Standards Institute, Inc., New York, August 30, 1991.

Postaccident Internal Inspection

On September 23, 1996, about 1 month after the accident, a 10-mile section of Koch's pipeline around the rupture site was inspected using a high-resolution MFL internal inspection tool. (The inspected section did not include that segment of pipe around the rupture that was removed after the accident.) The internal inspection was required by Hazardous Facility Order (HFO) CPF No. 46510-H that was formally issued on October 7, 1996, by the Office of Pipeline Safety (OPS), Research and Special Programs Administration (RSPA). The inspection identified numerous areas that were graded by the internal inspection company as having moderate and severe corrosion. Indications of severe corrosion were identified in about 15 lengths of pipe. These areas were not identified during the May 1995 inspection as having either moderate or severe corrosion.

External Corrosion Control

Koch uses an impressed current cathodic protection¹¹ system to mitigate corrosion on this pipeline. The *Koch Procedure Manual* (section 4.8.1) for this pipeline defined the minimum acceptable pipe-to-soil potential¹² level for adequate cathodic protection as at least -0.85 volts (V).¹³ To comply with 49 CFR 195.416(a), pipeline operators must perform annual testing to determine whether cathodic protection is adequate to control external corrosion. The regulation does not provide criteria for "adequate cathodic protection." Company corrosion technicians performed annual surveys¹⁴ of the cathodic protection system. Koch personnel also recorded cathodic protection readings on its field reports.¹⁵

¹¹ Cathodic protection is a corrosion mitigation method used by the pipeline industry to protect underground metal pipes using rectifier stations along the pipeline that supply protective electrical current. Cathodic protection current is forced to flow in the opposite direction of currents produced by corrosion cells. A rectifier converts alternating current from the utility service to direct current and supplies it to a ground bed that typically contains a string of suitable anodes, with soil as an electrolyte, to provide a path for the current from the rectifier to the pipeline. A cable connected to the pipeline provides the return path to the circuit.

¹² Defined as "the voltage difference between a buried metallic structure [pipe] and the electrolyte [soil], measured with a reference electrode in contact with the electrolyte [soil]." From Gordon, H. L., *Cathodic Protection*, Power Plant Electrical Reference Series, Project 2334, Electric Power Research Institute, Palo Alto, California, 1991, vol. 11, p. 11.2.

¹³ One of the cathodic protection criteria for pipelines transporting gas listed in 49 CFR 192, appendix D, is maintaining cathodic protection of at least -0.85 V pipe-to-soil potential to a saturated copper-copper sulfate half cell.

¹⁴ Pipeline companies perform pipe-to-soil potential surveys by measuring and recording the voltages and currents at test stations along the pipeline and at rectifiers. Measurement intervals vary widely from less than 100 feet to miles apart.

¹⁵ Koch refers to the company form used for field reporting of aerial, foreign crossing, exposed pipe, and pipeline revisions as a "4-in-1" report.

Preaccident Inspections and Action

Before the accident, six rectifiers were used in the pipeline cathodic protection system from Nevada to Corsicana pump stations. In the first quarters of 1994 and 1995, Koch personnel conducted an annual corrosion control survey that indicated the pipeline met the company standard for cathodic protection (pipe-to-soil potentials at least as negative as -0.85 V). During the annual survey in February 1996, potentials below the company's accepted protection level were recorded between rectifiers M-7 and M-10. The pipeline rupture occurred between rectifiers M-9 and M-9.5, which were the existing units on either side of the rupture location. (Figure 4 shows the location of the rectifiers and the rupture.)

In field reports completed after the May 1995 internal pipeline inspection, some readings indicated potential levels that did not meet the company standard. For example, records show that on August 28, 1995, an area about 1/4 mile south of the rupture had an approximate pipe-to-soil potential of -0.59 V and on August 24, 1995, an area 7/8 mile north of the rupture had a potential of -0.59 V. Similar low potentials were recorded up to 50 miles north of the rupture site to an area upstream of Nevada station.

On February 6, 1996, during Koch's 1996 annual survey, the output of rectifier M-8 was increased to improve pipe-to-soil potentials. On February 13, 1996, potentials as low as -0.68 V were recorded between rectifiers M-7 and M-8. Additionally, seven of nine readings taken on that date between rectifiers M-8 and M-9 were less negative than -0.85 V. These low potential measurements were in the -0.62 to -0.72 range.

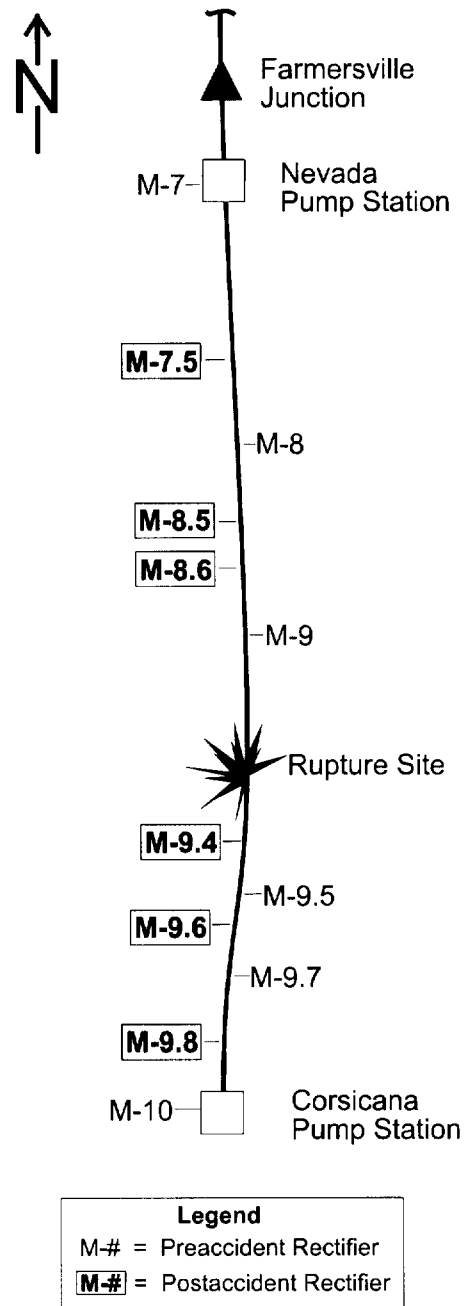


Figure 4. Koch pipeline rectifier sites M-7 through M-10

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Potential measurements taken between rectifiers M-9 and M-10 on February 13, 1996, were -0.815 V about 1.3 miles north of the rupture location and -0.827 V about 1.5 miles south. In addition to these readings, the lowest potential recorded on that date between rectifiers M-9 and M-10 was -0.78 V.

In a memorandum dated February 19, 1996, the corrosion supervisor recommended that a new rectifier be installed north of the eventual rupture site between M-8 and M-9. The area from rectifiers M-9 to M-10 was reported by the corrosion supervisor as having "good" readings. On February 26, 1996, Koch division personnel authorized installation of a new rectifier, which was initially labeled M-8.5 but was subsequently redesignated M-8.6.

On March 29, 1996, rectifier M-9 was not operating at its designated level and its ground bed needed replacement. No recorded pipe-to-soil readings are available for that date. Koch Division personnel discussed whether M-9 should be moved or the ground bed replaced. They decided to wait until the new rectifier was installed to verify its cathodic protection coverage and to determine how M-9 would be repaired.

Postaccident Inspections and Action

According to Koch, pipe-to-soil potentials were measured but not recorded for the accident site after the rupture on August 24, 1996. However, potential readings recorded 500 feet north and south of the rupture site on August 27 ranged from -0.49 V to -0.52 V. Shortly after the accident, on September 4, 1996, Koch replaced the ground bed for rectifier M-9. Koch installed the new rectifier (M-8.6) and activated it on September 11, 1996. Pipe-to-soil potentials taken during the close-interval survey¹⁶ in the rupture area remained low, about -0.65 V, after these rectifiers were activated.

After the rectifiers were activated, pipe-to-soil potentials were obtained during repair digs made following the September 23, 1996, internal inspection. Readings recorded on the field reports at several dig locations up to 1 1/4 miles north of the rupture ranged from -0.70 to -0.75 V and up to 1/4 mile south of the rupture ranged from -0.59 to -0.73 V. These areas were reported on the 1995 internal inspection survey as having either light (15 to 30 percent) or no reportable corrosion (< 15 percent). When the pipe was excavated after the accident, corrosion pinholes (very small-diameter holes through the pipe wall) were found, and corrosion pits greater than 0.180-inch deep were measured at several locations along the pipeline. These reports also noted that the pipeline coating

¹⁶ In a close-interval survey, pipe-to-soil potential is measured every few feet (typically every 2.5 feet). This survey is useful for identifying cathodic protection problems such as low potentials between established test points, the presence of stray currents, and areas of gross coating loss.

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had some "holidays" (breaks or bare spots), stress cracking, wrinkles, and disbonded areas.¹⁷ Tree roots were also observed in the backfill next to the pipe in one of these areas.

In October 1996, Koch completed a close-interval survey of the 10-mile section around the rupture site. Potentials less negative than -0.85 V were recorded in many areas during this survey. In addition, some areas of missing coating were noted. No indications of stray currents were found.

Additional rectifier installations were proposed for five new locations between Nevada and Corsicana pump stations as well as for other locations in the pipeline system. The last rectifier of this group was activated on February 17, 1997.

After the accident, the soil resistivity near the accident area was measured. Soil resistivity data are useful for determining corrosive characteristics of the soil and estimating their impact on cathodic protection. Low soil resistivity readings of 507 ohm-cm at the rupture site, 862 ohm-cm 50 feet north of the rupture site, and 1,149 ohm-cm 50 feet south of the rupture site were recorded. Soil resistivity values at these levels generally indicate highly corrosive soil.¹⁸

Pipe Examination

After the fire was extinguished, the accident site was excavated and the ruptured pipe exposed. The backfill contained partially decomposed organic material including tree roots and had a sewer-like odor. Shortly after the accident, about 95 feet of pipe was removed from the pipeline. A 46-inch section containing the rupture (figure 5) and three nearby sections (6 to 7 feet long) were examined at the Safety Board's Materials Laboratory in Washington, D.C.

The pipe rupture was longitudinal, approximately 12.5 inches long (figure 5, right to left). The rupture occurred at the 4 o'clock circumferential position relative to the pipe's position in the ground, with 12 o'clock being the top of the pipe. Significant corrosion was found at the center of the pipe rupture. Most of the tape coating on the ruptured segment was destroyed in the fire, thus the coating condition before the rupture could not be determined.

¹⁷ Cathodic protection current requirements are significantly reduced when buried pipeline is properly coated using an effective barrier coating. However, factors such as overprotection (potentials significantly more negative than -0.85 V), inadequate coating selection, improper surface preparation or application of the primer or coating, or soil stresses may result in coating disbondment. If soil or moisture is present on the pipe surface underneath the disbonded coating, the pipe could corrode even in a cathodically protected system. Because the disbonded coating acts as an electrical shield, the amount of current reaching the metal underneath the disbonded coating depends upon the resistance of the soil or water present in the gap created by the disbonded coating. Though some current may flow to the pipe surface in this space, more current goes to other, more easily accessible, areas (low resistance path). Typically, the current density underneath the disbonded coating is insufficient to provide adequate corrosion protection.

¹⁸ *Corrosion Control/Systems Protection*. Volume VI—*Technical Services*, Book TS-1, American Gas Association, Arlington, Virginia, 1986, p. 79.



Figure 5. Pipe section containing 12.5-inch rupture

The center of the rupture contained an area of corrosion about 5 inches long by 3 inches wide. In the rupture area, corrosion pits appeared to have substantially penetrated the pipe wall indicating nearly 100-percent wall-thickness loss. No other pitting was observed on the remainder of the 46-inch section of pipe containing the rupture. No evidence of a material flaw or of mechanical damage (dents, gouges, or scrapes) to the pipe was observed. Figure 6 is a composite of two photographs, one of each side of the rupture, constructed to show the two sides of the corroded area in proximity. The arrows in the photo indicate where corrosion pitting had substantially penetrated the pipe wall.

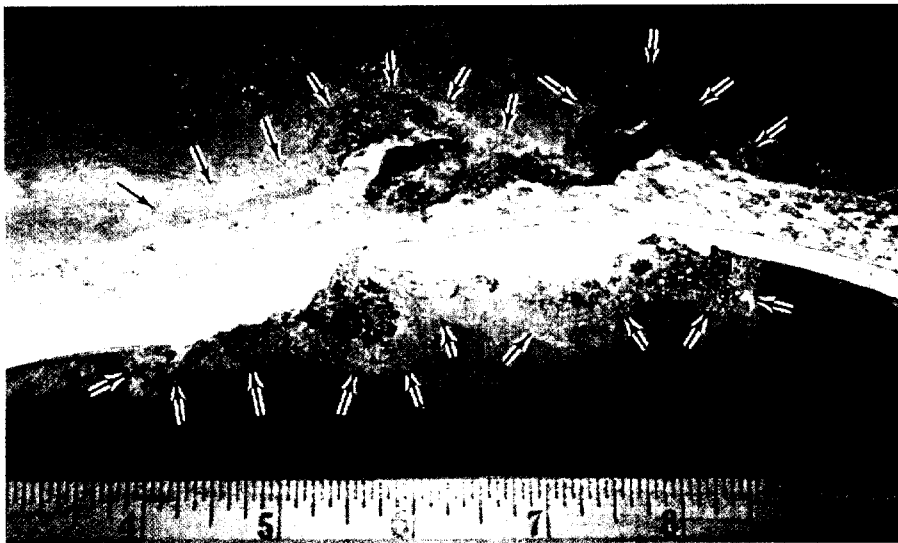


Figure 6. Composite photograph showing corroded area at center of rupture

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Coating damage as observed in the field is shown in figures 7 and 8. The three pipe sections (both upstream and downstream of the rupture) brought to the Materials Laboratory for testing had disbonded and cracked spiral wrapped tape coating at several locations. Mechanical damage to the tape coating similar to damage caused by a pipe-locating probe was also observed. Scratches were found on the pipe at several of the coating tears. Corrosion was observed on the exposed pipe surfaces at the damaged areas.



**Figure 7. Disbonded tape coating on 8-inch pipe extracted at accident site
(Arrows show disbonded area under tape coating.)**

All of the nearby pipe segments examined by the Materials Laboratory displayed corrosion damage, from 30- to 64-percent wall-thickness loss. Five principal areas of corrosion damage correlated with five corrosion areas on the 1995 inspection log; however, these areas had been graded as having less than 30-percent pipe-wall-thickness loss in 1995.

A consultant for Koch performed testing and analysis for bacteria¹⁹ on the pipe using a procedure similar to NACE International Standard TM 0194-94.²⁰ An area selected for bacteria testing included one of the corrosion areas containing rust tubercles²¹

¹⁹ Microorganisms, such as bacteria and fungi, can cause underground corrosion.

²⁰ NACE International Standard TM 0194-94, *Field monitoring of bacterial growth in oil field systems*. NACE International (formerly National Association of Corrosion Engineers—NACE), Houston, Texas, 1994.

²¹ Knob-like mounds formed on the pipe as the result of localized corrosion.

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within 20 feet of the rupture. The consultant's report provided the following laboratory analysis results:

- Pipe surface samples were acidic with a pH of 5 to 6,
- Sulfides were present in small amounts,
- Sulfate-reducing bacteria were present in insignificant amounts,
- Anaerobic acid-producing bacteria were present in small amounts (100 bacteria/ml), and
- Aerobic acid-producing bacteria were "strongly present" (10,000 bacteria/ml).

The consultant's report concluded, "The results of the testing performed here indicate that Aerobic Acid Producing bacteria are the main contributor to the corrosion found on this pipe."

Concerning the testing, the consultant's report said the results "may not be representative of bacteria activity" because of the inadequate sampling techniques and handling time. The report further noted, "Bacteria typically have a life of 30 to 40 hours and can change their populations significantly in 2 days if their environment is changed." In this instance, Koch had cleaned the pipe when it was removed from the ground, and laboratory tests were not performed until about 48 hours later. The consultant used tap water for sample preparation instead of the phosphate-buffered saline solution recommended in NACE International Standard TM 0194-94.



Figure 8. Cracks in the tape coating on 8-inch pipe excavated at accident site

Public Education

Preaccident Public Education Mailings

In 1991, Koch conducted a public education program for people living within 1/4 mile of the pipeline. In 1991 and 1992, public education materials were hand-distributed door to door by company representatives. In 1992, Koch produced a report that included tabulations of the total number of material packets issued and the response cards returned to the company.

From 1993 through early 1996, Koch distributed its public education materials by annual mailings, using addresses compiled from returned response cards, from lists developed by company representatives canvassing the area, and from property right-of-way records. Koch solicited and received public education information from other pipeline companies for comparison with its program. Koch representatives also attended industry meetings where public education information was reviewed.

An "Information Bulletin" was provided as part of the 1996 public education materials mailed to residents before the accident. (See appendix A.) The bulletin highlighted telephone numbers for notifying Koch before performing excavation near the pipeline or during a pipeline emergency. The bulletin discussed the propane-butane family of products transported by the pipeline, how to recognize a product release, and the importance of keeping "sources of ignition" away from liquid spill areas. In addition, the 1996 mailing included a calendar bearing a warning not to perform excavation near the pipeline until Koch is notified. Recipients also received response cards for providing their addresses and address corrections or for requesting additional information.

In 1996, about 45 families lived on two roads in the area of the accident, Oak Park Circle and County Road 4129 (figure 1). Of the 45 residences listed on the two roads, only 5 addresses appeared on Koch's 1996 preaccident mailing list. The two families that suffered fatalities were not on the mailing list. The person who called Koch to report the release was on the mailing list.

Koch's public education program provided educational materials to public offices and emergency response organizations serving the areas in which the pipeline was operated. The head of the Kaufman County Emergency Management Office indicated that Koch had provided information and communicated with the office. The Kaufman County Sheriff's Department was on Koch's mailing list and had been invited to yearly governmental liaison meetings in 1995 and 1996.

Industry Public Education Program Standard

American Petroleum Institute (API) Recommended Practice 1123, *Development of Public Awareness Programs by Hazardous Liquid Pipeline Operators*,²² provides information on reaching the public, safety message content, communications methods, and program evaluation. API Recommended Practice 1123 provides some information on resources available to companies for developing and distributing their own safety materials and on other methods of providing information. Section 6.8 of the publication states that “Operators that use their own mailing lists when they mail public awareness materials to the public should maintain up-to-date lists” and that response cards “permit the recipients to notify the operators of any changes of address and could measure the effectiveness of the safety message.” Section 9 provides information that a pipeline operator can use to evaluate the effectiveness of its public awareness program, including scientifically based evaluation techniques available to ensure that program objectives are being met (section 9.4).

Postaccident Public Education Mailing

As a result of an HFO issued after the accident by the OPS, Koch revised and reformatted its public education materials (appendix B). Some of the changes Koch made to its public education program include:

- Replacing its previous mailing list for residents along the pipeline right-of-way with a mailing list developed using mapping grid databases.
- Revising safety information to include pertinent information on detecting a pipeline leak and actions to take when a leak is suspected.
- Prominently highlighting material in the new safety brochure on:
 1. how to identify Koch’s pipelines,
 2. precautions to take around Koch’s pipelines during excavation activity,
 3. how to identify a pipeline leak and a highly flammable vapor cloud, and
 4. actions to take in addition to notifying Koch, when a leak is suspected or a vapor cloud is detected.

²² Recommended Practice 1123, *Development of Public Awareness Programs by Hazardous Liquid Pipeline Operators*, American Petroleum Institute, Washington, D.C., August 1996.

Regulations and Orders Governing Pipeline Operation

External Corrosion Control Safety Regulation

Title 49 CFR 195.416 contains a number of requirements concerning safe pipeline operations:

- (a): Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system that is under cathodic protection to determine whether the protection is adequate.
- (e): Whenever any buried pipe is exposed for any reason, the operator shall examine the pipe for evidence of external corrosion. If the operator finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extent of the corrosion.
- (g): If localized corrosion pitting is found to exist to a degree where leakage might result, the pipe must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness of the pits.

This regulation does not provide specific criteria for “adequate cathodic protection” for liquid pipelines. Specific criteria for cathodic protection can be found in appendix D of the gas pipeline safety regulations, 49 CFR 192.

Public Education Safety Regulation

Title 49 CFR 195.440 requires that pipeline operators establish a continuing education program to enable the public, appropriate Government organizations, and persons engaged in excavation-related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and report it to the operator or to fire, police, or other appropriate officials. The regulation does not specifically identify the information that must be provided or require that the pipeline operator periodically evaluate the effectiveness of its public education program. The OPS inspection of Koch’s public education program before the accident in May 1993 identified no deficiencies.

Office of Pipeline Safety Hazardous Facility Order

On October 7, 1996, about 6 weeks after the accident, the OPS issued an HFO that directed Koch to submit written plans, to include performing corrective actions concerning pipeline operation and public education. The HFO’s requirements include but are not limited to the following provisions:

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Submit for approval by the Regional Director, within 30 days after an Order is issued, a written plan addressing a program of tests or studies that will identify the extent of and propose a solution to the external corrosion problem on the HVL line and allow for verification and maintenance of the HVL line. The plan is to include, at minimum, provisions and time frames for identifying the extent of corrosion and correcting the external corrosion problems on the HVL line. The plan should address, at minimum—

The 8-inch [diameter] pipeline section [containing the accident location] between block valves at stations 17316+16 to 17849+48 (approximately 10 miles).

- i. Run an ultrasonic “smart” pig or high resolution magnetic flux “smart” pig [internal inspection instrument] to determine pipe wall condition.
- ii. Complete installation of new ground bed and test, and activate rectifier.
- iii. Perform a close interval survey.
- iv. Retain any exposed pipe removed from the line during preparation for the “smart” pig run [internal inspection] for OPS examination. Provide a detailed pipe and coating condition report.
- v. Notify the appropriate public officials of Henderson and Kaufman Counties whenever tests are performed involving the movement of HVLs through the pipeline.
- vi. Expose anomalies indicating 20 percent or greater wall loss, and repair or replace areas of 20 percent or greater wall loss, or as may be agreed upon with the Regional Director.
- vii. Determine MOP subject to final approval by the Regional Director.
- viii. The Corrosion mitigation measures must conform with approved industry standards such as NACE Standard RP-0169-92, *Recommended Practices for Control of External Corrosion on Underground or Submerged Metallic Piping Systems*.
- ix. Results of test and metallurgical and chemical analysis of pipe now underway.

Except for items ii, iii, and ix, the above requirements also apply to the remainder of the 8-inch and 10-inch-diameter sections of Koch’s HVL pipeline. In addition, the HFO modifies item v for those pipeline sections as follows: “Notify the appropriate public officials in affected counties whenever tests [are performed] involving the movement of HVLs through the pipeline.”

The HFO also addresses Koch’s public education program. The HFO specifies that Koch—

Factual Information

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Submit for approval by the Regional Director, within 30 days after an Order is issued, a written plan to provide a public awareness program for residents located along the pipeline right-of-way. The program, at minimum, should include the following information—

- a. Identification of pipeline location.
- b. Recognizing an HVL pipeline leak and action to be taken.
- c. Reporting to Koch any right-of-way encroachments or other activity which could damage the pipeline.
- d. Information about the danger of operating motorized vehicles and equipment in or near a vapor cloud caused by HVLs escaping from a ruptured pipeline.

Provide verification to the Regional Director that this program is being carried out.

Koch submitted the plan required by the HFO to the OPS.

Safety Issues

This analysis is divided into two general sections. The first section reviews the accident itself, highlighting the actions and events that resulted in problem conditions. The balance of the analysis discusses the safety issues identified as a result of this accident:

- Adequacy of Koch's corrosion inspection and mitigation actions, and
- Effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

Accident Discussion

At 2:05 p.m. on the day of the accident, the pump at Cleveland pump station (see figure 3) experienced an automated shutdown due to a hydrocarbon vapor detection alarm in the station. As a result of the shutdown, pressure increased on the pipeline upstream of Cleveland pump station. At 3:05 p.m., Corsicana pump station automatically shut down due to a high-discharge pressure alarm being activated. When the Corsicana pumps shut down, a pressure surge traveled from Corsicana upstream toward Nevada pump station. Based on an analysis of SCADA data, the pipeline ruptured between the two stations about 3:26 p.m.

No indications of excavation damage, such as dents or gouges on the pipe, were observed at the rupture site. The rupture occurred at a location where the pipe wall had been reduced due to corrosion. However, when the internal inspection tool was run about 15 months earlier, the wall-thickness loss in this area of the pipeline was identified as being significantly less than at the time of the accident. Therefore, this analysis examines the adequacy of Koch's corrosion inspection and mitigation actions.

When the pipe ruptured, it sent a butane vapor cloud into the surrounding residential area. The butane vapor ignited (figure 2) as two residents in a pickup truck drove into the vapor cloud on their way to a neighbor's house to report the release to 911. Therefore, the analysis also examines the effectiveness of Koch's public education program, particularly with respect to educating residents near the pipeline about recognizing hazards and responding appropriately during a pipeline leak.

Internal Pipeline Inspection

A possible explanation for the pipeline's rapid corrosion and failure in 15 months was that the 1995 internal inspection significantly underreported pipe-wall-thickness loss at the rupture site. Defect geometry related to size and orientation, such as dents, gouges, or narrow cracks in the longitudinal direction may create corrosion-feature-reporting problems. However, the Safety Board Materials Laboratory examination of pipe excavated near the rupture site identified no such defects. Also, comparison of actual wall-thickness-loss data with the internal inspection logs for the pipe locations excavated for repair by Koch showed good correlation. In the three instances where discrepancies between the 1995 log and the actual dig reports were observed, the internal inspection instrument predicted a wall-thickness loss that was greater than actually measured.

The Safety Board recognizes that the possibility of underreporting of corrosion damage at the accident site during the 1995 internal pipe inspection cannot be totally eliminated. However, the good correlation between the 1995 inspection log and actual dig reports and the absence of problematic defect geometry indicate that underreporting of corrosion damage probably did not occur. Therefore, the Safety Board concludes that it is unlikely that the pipeline corrosion damage near the rupture location was underreported by the 1995 internal inspection.

In addition, about 15 lengths of pipe in a 10-mile section around the rupture site were graded as exhibiting severe corrosion by the September 1996 internal inspection performed a month after the accident. However, none of the pipe lengths examined in the 1996 inspection had been identified as being either moderately or severely corroded by the May 1995 inspection. Therefore, the Safety Board concludes that corrosion damage found during the 1996 postaccident inspection indicated that rapid corrosion had occurred on the pipeline since the 1995 internal inspection.

Microbial Testing

A procedure similar to NACE International's TM 0194-94 oil field standard was used by Koch's consultant to obtain corrosion samples and test them for bacteria. The consultant's analysis of corrosion products from a pipe location within about 20 feet of the accident site indicated low levels of anaerobic bacteria and sulfides and an even smaller number of sulfate-reducing bacteria. The consultant noted that aerobic acid-producing bacteria were primarily present in the corrosion products. The consultant concluded that aerobic acid-producing bacteria mainly contributed to the pipe's corrosion. However, the report provided no information about the corrosion rate or time frame in which corrosion may have occurred.

The consultant's analysis could be inaccurate because Koch personnel cleaned the pipe after it was removed from the ditch and before the samples were collected. Another inaccuracy may have been introduced because laboratory tests were performed about

2 days after the pipe was removed from the ground. The consultant's report suggested that the adverse effect of the cleaning and delay in sampling might have been offset by the fact that samples were taken from tubercles on the pipe. However, these factors are important because of their significant impact on the aerobic and anaerobic bacteria populations. As noted in the consultant's report, bacteria typically have a life of 30 to 40 hours, and their populations can change significantly within 2 days of a change to their environment.

More importantly, and not specifically stated in the report, is the sensitivity of anaerobic and sulfate-reducing bacteria to an oxygen environment. The relevant factor in sample preparation was the use of tap water, which most likely contaminated the sample with oxygen and thus created a bias for aerobic microbes. No additional microbial testing was done, and the accuracy of the testing performed remains questionable. Therefore, the Safety Board concludes that the contribution of microbes to the corrosion damage cannot be accurately determined because of inadequate sampling and testing techniques. Furthermore, as noted earlier, Koch's consultant used a procedure similar to the one in the NACE International Standard (TM 0194-94), which describes field testing methods for estimating bacteria populations commonly found inside oil field piping systems and is not directly applicable to sampling and testing for microbes from an external pipeline surface. The Safety Board believes that NACE International should develop a standard for microbial sampling and testing of external surfaces on an underground pipeline.

External Corrosion Control

The cause of pipeline corrosion can be difficult to determine because different corrosion phenomena could operate simultaneously in the same general area, resulting in multiple damage sites with corrosion progressing at widely varying rates.

Stray currents constitute one phenomenon that can contribute to corrosion. However, the annual cathodic protection system surveys that Koch performed before the accident gave no indication that stray currents were present. Close-interval surveys performed after the accident in 1996 also indicated that the system did not have stray current problems. The Safety Board concludes that stray currents did not contribute to the corrosion observed on the pipeline.

Another factor that can contribute to corrosion is the failure to maintain adequate cathodic protection. After the internal inspection in 1995, the pipe-to-soil potentials recorded on field reports during repairs were below the acceptable cathodic protection level established by the company. Koch did not correct this observed low potential problem. The Safety Board therefore concludes that inadequate corrosion protection at the rupture site and at numerous other locations on the pipeline allowed active corrosion to occur before the accident.

Coating condition also affects the ability to adequately protect pipe from corrosion. Stress-cracked and disbonded coating was observed after the accident near the

rupture location. In the case of the pipe near the accident site, the stress-cracked and disbonded coating created areas where soil and moisture could come in contact with the pipe surface.

In addition to exposing pipe to microbial corrosion, stress-cracked and disbonded coating may have interfered with Koch's ability to provide adequate cathodic protection by exposing more bare pipe surface and consequently increasing the pipe's demand for protective current. The disbonded coating may have further decreased the effectiveness of cathodic protection by creating a barrier or shield to the protective current. The low potentials observed at a number of excavations before the accident indicated that the pipe was not receiving the necessary protective current. The Safety Board concludes that because cathodic protection levels were inadequate, the stress cracks that existed in the coating created areas in which rapid corrosion could occur. The Safety Board further concludes that the disbonded tape coating most likely created locally shielded areas on the pipe that prevented adequate cathodic protection current from reaching its surface, creating other areas where rapid corrosion could occur. In addition, the Safety Board concludes that stress cracks and disbonded tape coating on the pipe created areas where microbial corrosion could potentially occur.

Since the accident, Koch has taken action to improve corrosion protection on its pipeline. After the accident, pipe-to-soil potentials were still low in the vicinity of the rupture. Therefore, in the 2 weeks following the accident, Koch replaced an anode ground bed to repair one rectifier and installed the previously proposed new rectifier. By February 1997, the company had installed five additional rectifiers between rectifiers M-7 and M-10 because potentials were still below the company standard.

Koch also advised the Safety Board that it has been evaluating two alternatives to ensure the integrity of its line. One is to repair and re-coat a 70-mile section of its pipeline between Nevada and Corsicana pump stations; the other is to replace this 70-mile section of the pipeline. Koch has communicated these proposals to the OPS. The Board recognizes that the OPS has included a number of requirements in the HFO to specifically address identifying the extent of the external corrosion problem on the HVL pipeline. However, the HFO does not contain a specific requirement to evaluate coating condition, and Koch's field reports indicate that the corrosion problem extends beyond the 70-mile section proposed for repair or replacement. The Safety Board concludes that the tape coating on Koch's entire 8-inch pipeline may have stress cracking and disbondment. Therefore, the Safety Board believes that RSPA should require that Koch evaluate the integrity of the remainder of its HVL pipeline, including the condition of the coating, and rehabilitate the pipeline as necessary. Further, the Safety Board concludes because no overall requirement exists for operators to evaluate pipeline coating condition, problems similar to those that occurred on Koch's pipeline could occur on other pipelines. The Safety Board believes that RSPA should revise 49 CFR Part 195 to require pipeline operators to determine the condition of pipeline coating whenever pipe is exposed and, if degradation is found, evaluate the coating condition of the pipeline.

The OPS requires that pipeline operators conduct tests annually (not to exceed 15 months between tests) for pipelines under cathodic protection to determine that the protection is adequate (49 CFR 195.416). However, the regulation does not provide performance measures for “adequate cathodic protection” for liquid pipelines. Performance measures for cathodic protection can be found in appendix D of the gas pipeline safety regulations, 49 CFR 192. The Safety Board, as a result of its investigation of a 1986 accident²³ involving a liquid pipeline, recommended that RSPA provide cathodic protection criteria for liquid pipelines:

P-87-24

Revise 49 CFR Part 195 to include criteria, similar to those found in Part 192, against which liquid pipeline operators can evaluate their cathodic protection systems.

Because RSPA failed to take meaningful action to address this recommendation, the Safety Board classified Safety Recommendation P-87-24 “Closed—Unacceptable Action” on January 23, 1996. The Safety Board concludes that this accident illustrates the continuing need for performance measures for adequate cathodic protection on liquid pipelines and believes that RSPA should revise 49 CFR 195 to include performance measures for the adequate cathodic protection of liquid pipelines.

In addition to having appropriate cathodic protection performance measures, an operator should promptly evaluate all available corrosion-related data, such as potential measurements, internal inspection results, and coating condition to maintain adequate corrosion protection levels throughout a pipeline.

The need for a timely evaluation of corrosion-related data is evident in this accident. Catastrophic failure occurred in an area of the pipeline where significantly less corrosion had been identified by an internal inspection tool about 15 months earlier. Corrosion found on the pipe excavated as a result of the 1995 internal inspection confirms that active corrosion was occurring at various locations on the pipeline system. When buried pipe was exposed in 1995 after this internal inspection, Koch recorded low pipe-to-soil potentials on its field reports. Even though the recorded pipe-to-soil potentials in many cases were below the company standard for cathodic protection, Koch did not ensure that cathodic protection levels were restored to the company standard. In addition, stress cracking and disbonded coating were observed at numerous locations and recorded in the exposure reports. Excavations made as a result of the accident and during the 1996 internal inspection done after the accident indicate that active corrosion was continuing on the pipeline. The Safety Board concludes that although Koch’s records contained information that cathodic protection levels were inadequate and that active corrosion was occurring on its pipeline system before the accident, the conditions went uncorrected.

²³ For more detailed information, read Pipeline Accident Report—*Williams Pipe Line Company Liquid Pipeline Rupture and Fire, Mounds View, Minnesota, July 8, 1986* (NTSB/PAR-87/02).

Koch informed the Safety Board that as of September 1998, the company was expanding the distribution of its field reports and notifying corrosion technicians when specific conditions are detected so that a field inspection can be made. However, Koch needs to take more comprehensive action to evaluate data so that it can promptly provide adequate corrosion protection to its pipeline. The Safety Board believes that Koch should establish a procedure to promptly evaluate all data related to pipeline corrosion, such as annual cathodic protection surveys, field reports, internal inspection results, and coating condition data, to determine whether the pipeline's corrosion protection is adequate, and take necessary corrective action.

Public Education

The content of the 1996 bulletin sent by Koch (appendix A) as part of its public education package before the accident had two important shortcomings. The bulletin's first shortcoming was that key information on recognizing a leak and taking appropriate action lacked clarity and was not formatted to alert readers of its importance. In addition, the complex language used in the bulletin diluted the warning. For example, while the bulletin stated that vapors are extremely flammable, it also provided technical information on vapor ignition temperature and atmospheric concentration that distracted readers' attention from the message that such vapors pose a major hazard and require caution if their presence is suspected.

The bulletin's second shortcoming was that the warning was not specific enough. It omitted crucial information such as warning people not to operate switches, equipment, machinery, or motor vehicles in or near a vapor cloud; not to light a match or smoke; and not to drive into or go back into the vapor cloud. Furthermore, the bulletin failed to urge readers to inform others in the household of the warning, which is a way to disseminate crucial safety information beyond the initial reader. The Safety Board concludes that the format and content of the public education bulletin mailed by Koch before the accident did not effectively convey important safety information to the public.

Another significant issue involved the distribution of Koch's public education materials. Before the accident, Koch developed its mailing list through door-to-door canvassing and then used response card returns to verify the accuracy of coverage in the accident area. However, during the 1996 mailing, only 5 of the 45 residences near the accident site were sent Koch's educational materials. Significantly, Koch's 1996 mailing list did not include the two families that suffered fatalities in the accident. In all, Koch's mailing on the dangers of a pipeline release and actions to take during a pipeline emergency reached only a limited number of people living near the accident location. Therefore, the Safety Board concludes that Koch's distribution program for its public education materials before the accident was inadequate. Since the accident, Koch has improved the information presented in its educational bulletin and its method for distributing public education materials.

The pipeline safety regulations do not provide clear and specific requirements for the content and distribution of a pipeline operator's public education program. The lack of such requirements contributed to the failure, before the accident, to identify deficiencies in Koch's public education program. After the accident, the OPS issued an HFO that included requirements for Koch to improve its mailing list and revise its safety brochure to prominently feature information on recognizing a pipeline leak and on actions people should take in response to a leak.

Further, existing safety regulations do not require pipeline companies to evaluate the effectiveness of their public education programs. Without such evaluations, operators may not realize that a program is not achieving its objectives. One source for developing a scientific means to evaluate the effectiveness of public education programs is API Recommended Practice 1123, which contains information on evaluation methods. The Safety Board concludes that requirements for the content, format, and periodic evaluation of public education programs can help pipeline operators ensure that their programs are effective. The Safety Board believes that RSPA should revise 49 CFR Part 195 to include requirements for the content and distribution of liquid pipeline operators' public education programs. The Safety Board also believes that RSPA should revise 49 CFR Part 195 to require that pipeline operators periodically evaluate the effectiveness of their public education programs using scientific techniques.

The Safety Board has long been concerned about the issue of pipeline public education programs, including the content, distribution and the effectiveness of pipeline operators' safety materials for both hazardous liquid and natural gas pipelines. As a result its investigation of a series of 5 natural gas accidents²⁴ in Kansas, from September 16, 1988, to March 29, 1989, the Safety Board recommended on April 20, 1990, that RSPA:

P-90-21

Assess existing gas industry programs for educating the public on the dangers of gas leaks and on reporting gas leaks to determine the appropriateness of information provided, the effectiveness of educational techniques used, and those techniques used in other public education programs, and based on its findings, amend the public education provisions of the Federal regulations.

On April 5, 1993, RSPA published Advisory Bulletin ADB-93-02, which directed "gas pipeline facility owners and operators to review and assess their continuing education programs as applied to customers and the public." The Safety Board did not consider that action responsive because RSPA failed to assess the existing industry programs or amend the public education regulations. Therefore, the Board classified Safety Recommendation P-90-21 "Open—Unacceptable Action."

²⁴ For more detailed information, read Pipeline Accident Report—*Kansas Power and Light Company Natural Gas Pipeline Accidents, September 16, 1988 to March 29, 1989* (NTSB/PAR-90/03).

Safety Issues**26**

As a result of its investigation of a natural gas explosion and fire in Edison, New Jersey, on March 23, 1994,²⁵ the Safety Board reiterated Safety Recommendation P-90-21 to RSPA on February 7, 1995. The Board found that the Edison accident illustrated the need for RSPA to take an active role in ensuring that pipeline operator public education programs effectively provide the information the public needs to recognize the location of pipelines, recognize potential hazards, report a pipeline emergency condition, and safely evacuate an area.

Another recent accident investigated by the Safety Board in which public education was a major safety issue was the propane gas explosion in San Juan, Puerto Rico,²⁶ which resulted in 33 fatalities and 69 injuries. At the June 1997 public hearing, OPS's Director of the Enforcement, Compliance, and State Operations Division stated that the OPS had received \$800,000 in funding to develop a national public education program format to be used by pipeline operators. The OPS planned to work closely with industry to determine the most effective way to educate the public about gas pipeline safety. The Safety Board noted that although past actions on this issue had not been timely, it was pleased that the development of a national public education format was on RSPA's agenda and encouraged the OPS to expedite work on this project. Because of RSPA's renewed activity, the Board reclassified Safety Recommendation P-90-21 "Open—Acceptable Response" on December 21, 1997.

²⁵ For more detailed information, read Pipeline Accident Report—*Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994* (NTSB/PAR-95/01).

²⁶ For more detailed information, read Pipeline Accident Report—*San Juan Gas Company, Inc./Enron Corp., Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996* (NTSB/PAR-97/01).

Conclusions

Findings

1. The corrosion damage found during the 1996 postaccident inspection indicated that rapid corrosion had occurred on the pipeline since the 1995 internal inspection.
2. It is unlikely that the pipeline corrosion damage near the rupture location was underreported by the 1995 internal inspection.
3. Stray currents did not contribute to the corrosion observed on the pipeline.
4. Inadequate corrosion protection at the rupture site and at numerous other locations on the pipeline allowed active corrosion to occur before the accident.
5. Because cathodic protection levels were inadequate, the stress cracks that existed in the coating created areas in which rapid corrosion could occur.
6. Disbonded tape coating most likely created locally shielded areas on the pipe that prevented adequate cathodic protection current from reaching its surface, creating other areas in which rapid corrosion could occur.
7. Although Koch's records contained information that cathodic protection levels were inadequate and that active corrosion was occurring on its pipeline system before the accident, the conditions went uncorrected.
8. The tape coating on Koch's entire pipeline may have tape cracking and disbondment.
9. Because no overall requirement exists for operators to evaluate pipeline coating condition, problems similar to those that occurred on Koch's pipeline could occur on other pipelines.
10. This accident illustrates the continuing need for performance measures for adequate cathodic protection on liquid pipelines.
11. Stress cracks and disbonded tape coating on the pipe created areas where microbial corrosion could potentially occur.
12. The contribution of microbes to the corrosion damage cannot be accurately determined because of inadequate sampling and testing techniques.
13. The format and content of the public education bulletin mailed by Koch before the accident did not effectively convey important safety information to the public.

Conclusions

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14. Koch's distribution program for its public education materials before the accident was inadequate.
15. Requirements for the content, format, and periodic evaluation of public education programs can help pipeline operators ensure that their programs are effective.

Probable Cause

The National Transportation Safety Board determines that the probable cause of this accident was the failure of Koch Pipeline Company, LP, to adequately protect its pipeline from corrosion.

Recommendations

As a result of its investigation of this accident, the National Transportation Safety Board makes the following safety recommendations:

to the Research and Special Programs Administration:

Require that Koch Pipeline Company, LP, evaluate the integrity of the remainder of its HVL (highly volatile liquid) pipeline, including the condition of the coating, and rehabilitate the pipeline as necessary. (P-98-34)

Revise 49 *Code of Federal Regulations* Part 195 to require pipeline operators to determine the condition of pipeline coating whenever pipe is exposed and, if degradation is found, to evaluate the coating condition of the pipeline. (P-98-35)

Revise 49 *Code of Federal Regulations* Part 195 to include performance measures for the adequate cathodic protection of liquid pipelines. (P-98-36)

Revise 49 *Code of Federal Regulations* Part 195 to include requirements for the content and distribution of liquid pipeline operators' public education programs. (P-98-37)

Revise 49 *Code of Federal Regulations* Part 195 to require that pipeline operators periodically evaluate the effectiveness of their public education programs using scientific techniques. (P-98-38)

to Koch Pipeline Company, LP:

Establish a procedure to promptly evaluate all data related to pipeline corrosion, such as annual cathodic protection surveys, field reports, internal inspection results, and coating condition data, to determine whether the pipeline's corrosion protection is adequate, and take necessary corrective action. (P-98-39)

to NACE International:

Develop a standard for microbial sampling and testing of external surfaces on an underground pipeline. (P-98-40)

Recommendations

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BY THE NATIONAL TRANSPORTATION SAFETY BOARD

JAMES E. HALL
Chairman

JOHN A. HAMMERSCHMIDT
Member

ROBERT T. FRANCIS II
Vice Chairman

JOHN J. GOGLIA
Member

GEORGE W. BLACK, JR.
Member

November 6, 1998

Appendix A

Public Education Information Bulletin (issued before 1996 accident)



KOCH PIPELINE COMPANY LP

INFORMATION BULLETIN

Koch Pipeline Company, L.P. and Koch Hydrocarbon Company, in a continuing effort to inform the public about the operation of its pipeline systems, would like to pass on to you some pertinent information in the event that you are working near our pipeline.

The Koch Pipeline systems were established to safely and efficiently gather natural gas liquids in the states of Oklahoma, Texas, New Mexico and Kansas and transport them to Medford, Oklahoma, Hutchinson, Kansas or Mont Belvieu, Texas for separation into specification products.

The welded steel pipelines were constructed in accordance with applicable state and federal regulations and are monitored from a pipeline control center in Wichita, Kansas. This control center is operated by personnel on duty 24-hour a day, seven days a week.

The pipelines operate at pressures from 740 to 1440 psi. The natural gas liquids, which are of the propane-butane family, would quickly vaporize into a flammable gas if released to the atmosphere. A large spill will create a fog-like cloud from atmosphere moisture being condensed, but the gas itself is colorless. Depending on weather conditions, it can collect in low places, become transparent or dissipate into the atmosphere.

The product is not odorized, but usually can be identified by the typical petroleum product odor. The vapors are extremely flammable, having an ignition temperature of approximately 800° F in an atmosphere containing 2% to 10% mixture of vapor. All care should be taken to keep sources of ignition a safe distance from any liquid spill area.

Our greatest concern regarding line failure is with others working near the pipeline with earth moving equipment. We have an ongoing program of advising the public of the location of our pipeline, requesting that they call us prior to digging near the pipeline. The location of our line is marked with signs and markers which indicates the presence of the line. The only sure way of locating our pipeline, is by calling the number listed on the markers and having our company representative come out and flag the line. Digging near our lines without knowing exactly where the pipelines are located can result in a pipeline rupture and possible risk to personal safety.

Should a failure or malfunction of the pipeline system occur, our operating personnel will notify various agencies and/or companies as assistance is required. Likewise, if you are the first to be informed, notify us by calling our pipeline control center in Wichita at 800-666-9041 or 800-666-0125.

In addition to the control center monitoring the pipeline, the Company has operating and maintenance personnel located at various points along the pipeline. In the event of an incident, these personnel have training in the response to a pipeline emergency and would be responsible for the orderly handling of an emergency situation. They will be in a position to advise public agencies of the magnitude of the problem and how best to cope with it. If evacuation of people in the vicinity is warranted, the Company Representative will so advise and will assist the various agencies and/or companies in the notification.

If you desire further information, please contact Koch Pipeline Company, L.P. or Koch Hydrocarbon Company at our Medford Division office, phone 405-395-2377, during normal business hours.

**BEFORE EXCAVATING OR IN CASE OF EMERGENCY
800-666-9041 or 800-666-0125**

Appendix B

Revised Pipeline Safety Brochure (issued since 1996 accident)

K KOCH
Koch Pipeline Company LP

PIPELINE SAFETY

WARNING
HIGH PRESSURE
PETROLEUM PIPELINE
K KOCH
Koch Pipeline Company LP
Medford, Oklahoma
1-800-666-9041

What To Do If You Find A Pipeline Leak

Pipeline leaks can form a highly flammable white fog called a "vapor cloud." If you find a pipeline leak or suspect there might be a problem on the pipeline, please take the following precautions:

- Turn off any machinery and/or equipment in the immediate area. (Note: If a vapor cloud has surrounded a piece of running equipment, **do not go into the vapor cloud** to turn off the equipment.)
- Do not create any sparks or heat sources which could ignite escaping gas or liquids. For example, do not start a car, turn on or off any light switches, or light a match or cigarette. Turn off any lit gas pilots.
- Immediately leave the area on foot in a crosswind direction away from the vapor cloud and maintain a safe distance.
- Warn others to stay away from the leak.
- Do not drive into or near a vapor cloud. The car engine might ignite the vapor cloud.

How Can You Identify A Natural Gas Liquids Pipeline Leak

Often you can see a pipeline leak and in many cases you can smell it. The following signs might indicate a pipeline leak:

- A strange or unusual odor near the pipeline (the products will have a typical petroleum odor)
- A hissing or roaring sound (from escaping gas)
- A patch of dead or discolored vegetation in an otherwise green setting along the pipeline
- A slight mist of ice or a frozen area on exposed pipes, valves or the ground
- Flames originating from the ground or valves along the pipeline route
- Continuous bubbling in wet, flooded areas or marshlands, rivers, creeks and bayous
- Depending on weather conditions, leaked gas can collect in low places, become transparent or dissipate into the air
- A dense white cloud of fog

Information you need to know about pipelines.

Notify us and give your name, the location and a description of the leak. For our pipelines call us at 800-666-9041 or 800-666-0125.

Appendix B

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Hello Neighbor

Please read and share with your family this information about the pipeline that runs through your area. These background facts and safety instructions will help you avoid potentially dangerous activity around the line and guide you to proper actions if you see or suspect a problem.

Who is Koch Pipeline Company, L.P.

Koch Pipeline Company, L.P. is a pipeline operating company with lines that gather and transport natural gas liquids in Oklahoma, Texas, New Mexico and Kansas. Koch provides transportation services for many different companies that need to move products throughout the central United States. Koch owns and operates more than 8,000 miles of gas liquids pipelines.

Koch operates a pipeline control center in Wichita, Kansas, 24 hours a day, seven days a week in which technicians keep track of flow and pressures in our lines. In addition to the pipeline control center, Koch has operations & maintenance people located at various points along the pipeline and conducts frequent aerial patrols of the pipelines.

Koch transports natural gas liquids consisting of a mixture of ethane, propane, butane, natural gasoline, ethane-propane mix and propylene. These products are also commonly known as NGL – Natural Gas Liquids, LPG – Liquefied Petroleum Gas, or HVL – Highly Volatile Liquid.

Pipelines Make Good Neighbors

Pipelines carry gas and liquids used in the manufacture of many vital consumer products such as paints, plastics

and clothing.

Pipelines have the best safety record in the transportation industry and we need your help, as our neighbor along the pipeline, to keep it that way.

It is unlikely that we would experience a leak, but should a leak occur, the information contained in this brochure will help you:

- Know how to identify our pipelines by our signs and markers
- Know how to recognize a leak
- Know what to do if you notice a leak
- Know how to immediately report a leak

By working together, we can keep our pipeline operating safely and quietly without any disturbances or inconvenience to our neighbors. If you have questions about this safety information or our operations in your area, please write us at the following address:

Koch Pipeline Company, L.P.
Safety Department
P.O. Box 29
Medford, Oklahoma 73759

Or, you can call us in Medford at (405) 395-2377 during normal business hours.

Why Transport Products by Pipeline

Pipelines are by far the safest means of transporting liquid products. Statistics from the federal government show pipelines have a safety factor unequal to any other mode of transportation. If it were not for underground pipelines, all petroleum products would need to be transported by truck, rail car or barge at a greater risk to the public and the environment.

Pipelines are constructed of steel pipe and are protected to prevent corrosion (rust). Assuming nothing strikes the pipeline, a properly designed, constructed, operated and maintained pipeline can last indefinitely.

How To Identify Our Pipelines

Since most pipelines are underground, pipeline markers are used to show their approximate location. We have installed the colorful pipeline markers shown below at public roads, railroad and river crossings and various other places along the pipeline's path.

**Working Around Our Pipeline**

The number one cause of pipeline leaks is third-party damage (excavation, posthole digging, etc.). If you plan to dig or construct anywhere near our pipeline, call our pipeline control center at 1-800-666-9041 or 1-800-666-0125. We will then identify the location of our pipeline for you by sending a pipeline representative to locate and mark our pipeline prior to any work performed in the area.

It is important that you phone us immediately if you strike our pipeline. Even seemingly minor damage, such as a dent, clipped or scraped pipeline coating, is serious because it could result in a future leak or incident if not

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<p>REPORTER'S RECORD</p> <p>VOLUME 5 OF 24 VOLUMES</p> <p>TRIAL COURT CAUSE NO. 51458</p> <p>DANNY SMALLEY, INDIVIDUALLY) IN THE DISTRICT COURT</p> <p>AND AS INDEPENDENT)</p> <p>ADMINISTRATOR OF DANIELLE)</p> <p>DAWN SMALLEY, DECEASED)</p> <p>VS.) KAUFMAN COUNTY, TEXAS</p> <p>KOCH INDUSTRIES, INC., KOCH)</p> <p>PIPELINE COMPANY, L.P.,)</p> <p>KOCH HYDROCARBON COMPANY,)</p> <p>KPL/GP, INC., AND RONALD)</p> <p>GANT) 86TH JUDICIAL DISTRICT</p> <p>TRIAL ON MERITS</p> <p>On the 7th day of October, 1999, the following proceedings came on to be heard in the above-entitled And numbered cause before the Honorable Glen M. Ashworth, Judge presiding, held in Kaufman, Kaufman County, Texas:</p> <p>Proceedings reported by machine shorthand.</p>	<p>1 WITNESS INDEX Page 3</p> <p>2 Voir</p> <p>3 Direct Cross Redirect Recross Dire</p> <p>4 DANNY</p> <p>5 MILLS 6</p> <p>6 ROBERT</p> <p>7 MEHL 14</p> <p>8 KARA</p> <p>9 SHORT 29</p> <p>10 JAMES</p> <p>11 CRADDOCK 46 58</p> <p>12 MARY</p> <p>13 CRUTCHFIELD 64</p> <p>14 TIMOTHY</p> <p>15 THORP 93 103</p> <p>16 MELANIE</p> <p>17 MAYFIELD 111 129</p> <p>18 DANIEL</p> <p>19 MAYFIELD 130 152</p> <p>20 JAMES</p> <p>21 TUCKER 154 189</p> <p>22 EDWARD</p> <p>23 ZIEGLER 203 222</p> <p>24 222 238</p> <p>25 239</p> <p>26 ALPHABETICAL WITNESS INDEX</p> <p>27 Voir</p> <p>28 Direct Cross Redirect Recross Dire</p> <p>29 JAMES</p> <p>30 CRADDOCK 46 58</p> <p>31 MARY</p> <p>32 CRUTCHFIELD 64</p>
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1 Rules, Professional Conduct, Mr. Lyon was not allowed
2 to do that, could not do that, and has violated the
3 Disciplinary Rules.
4 We need to make an objection and move the
5 Court to strike the entirety of Dr. Mehl's testimony on
6 that basis.
7 THE COURT: Okay. That's denied.
8 MR. LYON: Judge, --
9 THE COURT: I don't need to hear any more
10 about that. I've had an issue like that go to the
11 Supreme Court. That's disciplinary --
12 MR. LYON: This, this has nothing to do
13 with that.
14 THE COURT: Okay. What is it?
15 MR. LYON: The only reason I would be
16 going out -- I'm trying to line up these witnesses.
17 THE COURT: I know you are. I'm just
18 telling you --
19 MR. LYON: I will not go to the bathroom,
20 Your Honor, I swear.
21 (Off-the-record discussion.)
22 (Jury ushered in.)
23 THE COURT: All right. Go ahead, sir.
24 MR. McCAULEY: Your Honor, once again,
25 we're going to call James Roger Craddock by deposition,

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1 portions of a deposition taken on March 5, 1999.
2 THE COURT: All right.
3 MR. McCAULEY: He, again, is defendants'
4 expert.
5 JAMES ROGER CRADDOCK,
6 having been duly sworn, testified as follows by
7 videotape deposition:
8 DIRECT EXAMINATION
9 BY MR. McCAULEY:
10 (Videotape playback begins.)
11 Q State your name, please.
12 A My full name is James Roger Craddock.
13 Q Tell me, if you would, just generally
14 speaking, what you did for Koch in this case.
15 A I was involved with Koch in this case to
16 assist Koch in trying to determine what happened with
17 regard to this particular fire.
18 Q When you say what happened, what do you mean,
19 "what happened"? We know what happened. It caught on
20 fire, and it burned. But what, what part do you mean
21 --
22 A What I was interested in is trying to
23 determine, if we could, where the butane, once it was
24 released, may have gone; how much may have escaped; how
25 much -- if we could do a gas dispersion model to

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1 determine with some specifics where we thought various
2 concentrations may be; to determine, if we could, what
3 we felt the ignition source that ultimately ignited
4 this particular butane was.
5 I think, essentially, that was it.
6 Q In other words, did you try to calculate the
7 amount of gas that you believed to escape prior to the
8 ignition?
9 A Yes.
10 Q Okay. What number did you come to? What
11 volume?
12 A The total number that we felt had escaped from
13 the pipeline prior to ignition was approximately 58,000
14 cubic feet of liquid.
15 Q At any given point you could cut off and say
16 that this pipe contains a certain amount of volume --
17 A Yeah. I've got --
18 Q -- at any point in time?
19 A Assume it's 70 miles, for sake of our
20 discussion.
21 Q Right.
22 A You've got an eight-inch pipeline at 70 miles.
23 It's got a given volume.
24 What we want to know, is how much is actually
25 flowing through.

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1 Q Which is, then, a function of the pressure and
2 the pumps; is that correct?
3 A Exactly. Exactly.
4 Q So the first thing you do, is you figure out
5 what's the -- what's the given volume of that pipe
6 under normal circumstances; then, what is the flow rate
7 through that pipe at different pressures?
8 A Yeah.
9 Q The flow rate is going -- is, in large part,
10 going to determine how much is escaping; is that true?
11 If you just -- in other words, if you just
12 blocked off at Nevada and Corsicana and it was
13 static -- it was just held in there, and it wasn't
14 moving. It was just under pressure. Then you
15 calculate your discharge out the hole, just by knowing
16 what the dissipation rate would be under a certain
17 pressure through that hole, I take it?
18 A That's true.
19 Q So, in other words, are you saying that as --
20 as the -- as the rupture occurs, you have an initial
21 ejection because it's under, let's say, 1440 pounds of
22 pressure?
23 A Right.
24 Q You have an initial ejection of liquid that
25 becomes gas?

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1 Q A little over 200 to one expansion rate?

2 A Right. You can do it the way I just gave you,
3 and it will -- it will come up to whatever it is. But
4 it's about -- I want to say 2 -- maybe as high as 220.
5 It's -- it's less than -- than -- because it's a
6 heavier gas.

7 Q All right. And as it escapes, -- as you just
8 said, it's a heavier gas. Then it has a tendency to do
9 what as it escapes out of the pipeline? Follow the
10 ground terrain, to drop down?

11 A Yeah. It -- when -- when the liquid escapes
12 from the pipeline, -- and that's what's going to
13 escape -- it's going to want to try to vaporize. All
14 right. There are two things that take place.

15 The liquid is much like water, even though
16 it's lighter than water. But basically, it's -- as it
17 begins to develop and, and convert to gas, butane has
18 got a specific gravity of about 2.1 versus 1 for air,
19 so it's roughly twice as heavy.

20 Q As?

21 A As air. So it has a tendency to want to stay
22 low.

23 In addition to that, because of the heat
24 required to vaporize the butane from liquid to gas, the
25 latent heat of vaporization -- it's pulling that heat

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1 from wherever it can get it, and basically that's from
2 the ambient air.

3 Q From the ambient atmosphere?

4 A So it will start to try to refrigerate a
5 little. So putting all of that in something simple
6 is -- basically, it's going to want to stay low. It's
7 going to want to try to hug the ground, and it's going
8 to want to diffuse down as it moves down and continues
9 to vaporize.

10 Q Now, as it -- as it goes through this
11 vaporization process, it does then pull, actually pull
12 temperature out of the ambient atmosphere, convert it
13 as part of the conversion -- cool down on the
14 atmosphere around it; is that correct?

15 A Right. A lot of times, when you see either
16 liquid propane or liquid butane -- where you see the
17 so-called vapor cloud, what you're really seeing is the
18 crystallized water vapor that's within the air because
19 it's frozen, due to the pulling of the heat to the --

20 Q It's not the same process?

21 A What, what you're doing here is you're
22 changing the physical state of, of the, the element.

23 In other words, in this case, butane.

24 Q You're -- all right.

25 A You're taking it from liquid to propane -- to

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1 vapor. To do that, it -- heat --

2 Q It takes heat?

3 A The latent heat of vaporization, that heat
4 required to change from one medium to another.

5 Q So that when witnesses to this have testified
6 that they saw -- that they could actually see something
7 happening, that they saw a cloud or a vapor cloud,
8 that's consistent with what you would expect, isn't it?

9 A Right.

10 Q And you know that some of them testified they
11 saw that vapor cloud or what appeared to be a cloud;
12 isn't that correct?

13 A Right.

14 Q And you -- from a scientific standpoint, that
15 is consistent with what you would expect to happen in
16 the process of conversion; is that correct?

17 A Yep.

18 Q Okay. Now, if we could, just, just calculate
19 for me, then. I'll go back to my question to you a
20 while ago.

21 Approximately how many gallons do you estimate
22 of converted butane gases escaped that day?

23 A Till the time of the incident?

24 Q Yes. Till the time of the fire, the ignition.

25 A You've got 58,000 -- say, roughly, 58,000

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1 cubic feet. You've got 7.48 gallons per cubic foot.

2 So multiply 58,000 time -- by roughly 7.5, and
3 that's, that's pretty close.

4 Q Okay. Which is going to be about 300 and --

5 A Close to 400,000.

6 Q -- 89 or 90,000. But --

7 A It would be close to 400,000 gallons. Yeah.

8 Q And would that, I guess -- let me go through
9 that step.

10 What is the conversion rate to barrels?

11 You've got 400,000 gallons, converted --

12 A Forty-two gallons is considered to be a
13 barrel.

14 Q And, and that would be true for propane and
15 other gases?

16 A Any, any liquid.

17 Q So roughly -- just tell the jury about how
18 many barrels we're talking about here. Out of 400,000
19 gallons, about how many barrels is that?

20 A Four -- a little over 40,000.

21 Q Okay. Just a tad over 40,000 barrels?

22 A Wait a minute. That's not right.

23 Q Is that -- actually, it would be --

24 A Be half that.

25 Q Less than that. Be a little less than that?

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1 Q Exhibit 5 to your deposition, next to
2 rectifier M9, where you had written over your earlier
3 remarks that that rectifier was down and had included
4 a value -- do you believe that that was sometime after
5 September 19, 1995?
6 A No. I feel like it was within a few days
7 after the first one I faxed in or mailed in.
8 Q Which could have been September 20th or
9 September 26th, 1995?
10 A That's what I filled out.
11 Q Okay. Have you ever heard of the term
12 "railroading"?
13 A No.
14 Q No?
15 A No.
16 (Videotape playback concluded.)
17 MR. BRENNAN: Your Honor, that concludes
18 our cross-examination of Mr. Tucker, with the
19 reservation we may call him in our case in chief.
20 MR. MCCAULEY: We have no redirect, Your
21 Honor.
22 THE COURT: Call your next witness.
23 MR. LYON: At this time, Your Honor,
24 we'll call Ed Ziegler. Ed Ziegler.
25 (Pause.)

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1 MR. LYON: We'd also like to offer into
2 evidence, for the Court to take judicial knowledge of,
3 Section 49 CFR, Chapter 10.1 -- Chapter 1, Part 195,
4 transportation of hazardous liquids by pipeline, Code
5 of Federal Regulations, Regulations.
6 MR. STEINDORF: This is just 195?
7 MR. LYON: Yes.
8 THE COURT: Please, sir, raise your right
9 hand.
10 (Witness sworn.)
11 MR. STEINDORF: No objection.
12 THE COURT: And, and, and please be
13 seated.
14 And that number is --
15 MR. LYON: That number is Plaintiff's
16 Exhibit No. 30.
17 THE COURT: It's admitted.
18 MR. LYON: Or it should be. I've got 29,
19 actually.
20 THE COURT: What number is --
21 MR. LYON: 30.
22 THE COURT: 30? Okay. It's admitted.
23 (Plaintiff's Exhibit No. 30 admitted.)
24 THE COURT: Go ahead, sir.
25 EDWARD R. ZIEGLER,

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1 having been duly sworn, testified as follows:
2 DIRECT EXAMINATION
3 BY MR. LYON:
4 Q State your name for the record, please.
5 A Edward R. Ziegler, Z-I-E-G-L-E-R (spelling).
6 Q Mr. Ziegler, is this a copy of your curriculum
7 vita?
8 A Yes, sir.
9 Q And this is Plaintiff's Exhibit No. 29;
10 correct?
11 A Yes.
12 MR. LYON: At this time we'll offer into
13 evidence Plaintiff's Exhibit No. 29.
14 MR. STEINDORF: No objection.
15 THE COURT: It's admitted.
16 (Plaintiff's Exhibit No. 29 admitted.)
17 Q (by Mr. Lyon) Mr. Ziegler, would you tell the
18 jury what you do for a living?
19 A I'm a petroleum and safety consultant, located
20 in Houston, Texas.
21 Q And as a petroleum and safety consultant, give
22 the jury your educational background.
23 A I have a Bachelor of Science degree in
24 petroleum and natural gas engineering from Penn State
25 in 1972. I also have 15 credits of master's level

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1 safety engineering courses. I also have a law degree
2 from South Texas College of Law in Houston in 1979.
3 Q Where did you grow up, sir?
4 A I grew up in northwestern Pennsylvania.
5 Q And when did you move to Texas?
6 A I moved to Texas in 1973. I graduated from
7 college. Was in the International Guard for about six
8 months. Then I went to work for an oil company,
9 Marathon Oil Company, and they transferred me to
10 Houston in about 1973.
11 Q Now, when you graduated as a petroleum
12 engineer from college, what -- where did you go to
13 work?
14 A I first went to work in Illinois for Marathon
15 Oil Company. I was then transferred to Houston. I
16 worked for Marathon in Houston, Lafayette, and a number
17 of other locations in the United States and overseas.
18 Q Have you had occasion to supervise pipeline
19 safety?
20 A Yes.
21 Q When did that -- when did you first have
22 occasion to do that?
23 A I first started working on pipeline safety
24 issues when I was working for Marathon, starting in
25 1972.

<p style="text-align: right;">Page 221</p> <p>1 objection. Vague. Unless Counsel makes clear which 2 safety system he's talking about. And if, if not, it's 3 irrelevant.</p> <p>4 THE COURT: Well, I'm going to let you 5 rephrase it in a more specific question.</p> <p>6 Q (by Mr. Lyon) In order to protect the public, 7 employees, equipment, and product, what are the 8 elements of the safety -- of a safety system for 9 protecting a pipeline?</p> <p>10 MR. STEINDORF: Same objection, Your 11 Honor.</p> <p>12 THE COURT: I'm sorry, sir?</p> <p>13 MR. STEINDORF: Same objections, Your 14 Honor. It -- I don't know which pipeline Mr. Lyon is 15 referring to or which specific system he's referring 16 to, and the witness hasn't said.</p> <p>17 Objection. Vague. And, and also, 18 objection. Irrelevant.</p> <p>19 THE COURT: Well, in which way do you 20 believe it to be vague?</p> <p>21 MR. STEINDORF: Well, the, the question 22 is, "Start defining a system."</p> <p>23 But Counsel hasn't suggested that the 24 witness is defining the Koch system, and he hasn't 25 suggested that the witness is defining any system</p>	<p style="text-align: right;">Page 223</p> <p>1 BY MR. LYON:</p> <p>2 Q In regard to the design of --</p> <p>3 THE COURT: Let me say this, Mr. Ziegler.</p> <p>4 You, you -- you're prone -- your voice is prone to kind 5 of drift out a little bit. If you could, project 6 throughout the entire response.</p> <p>7 THE WITNESS: Yes, sir.</p> <p>8 THE COURT: Thank you.</p> <p>9 MR. LYON: You might want to sit up and 10 project out.</p> <p>11 THE COURT: We've been through this 12 projection earlier. I mean, we, we all know what to 13 project means --</p> <p>14 MR. LYON: I've never had a trial where 15 there are so many soft-voiced witnesses.</p> <p>16 Q (by Mr. Lyon) Let's, let's talk about the 17 design of safety systems for pipelines. And let's talk 18 to protect the public, employees, and equipment and 19 product.</p> <p>20 What are the elements of a safety system that 21 a reasonable and prudent pipeline company ought to take 22 into consideration when they have pipe in the ground, 23 running in -- close to homes?</p> <p>24 A The, the three primary elements would be the 25 public information system, and it would be the --</p>
<p style="text-align: right;">Page 222</p> <p>1 prescribed by the regulations. So it's, it's vague. 2 It's also irrelevant unless it's one of 3 those.</p> <p>4 May I take the witness on voir dire for 5 two questions?</p> <p>6 THE COURT: Sure.</p> <p>7 VOIR DIRE EXAMINATION</p> <p>8 BY MR. STEINDORF:</p> <p>9 Q Mr. Ziegler, are you just talking about 10 general principles about how a pipeline ought to be 11 made safe?</p> <p>12 A That was my understanding of the question.</p> <p>13 Q You're not referring specifically to, to Koch 14 or to the CFR?</p> <p>15 A Well, I'm referring to both of those things: 16 first, in terms of this lawsuit; and second of all, 17 I've been asked several questions about the CFR, which 18 was, what are the elements of pipeline safety I just 19 mentioned.</p> <p>20 Q All right. Well, I think I understand your 21 answer.</p> <p>22 MR. STEINDORF: I'll withdraw objections, 23 Your Honor.</p> <p>24 THE COURT: All right. Go ahead.</p> <p>25 DIRECT EXAMINATION RESUMED</p>	<p style="text-align: right;">Page 224</p> <p>1 number two, the training and knowledge of the company's 2 people; number three, the protection of the pipeline, 3 which would be done primarily by coatings, secondly by 4 cathodic protection.</p> <p>5 Q All right. Let's, let's get -- let's get some 6 definitions and have those, so the jury can understand 7 what we're talking about when we're talking about 8 pipeline safety.</p> <p>9 What is a rectifier?</p> <p>10 A A rectifier is an electronic device that 11 forces electric current to travel in one direction and 12 is adjustable. The rectifier system converts AC 13 current, which is a two-way current that comes from the 14 electric pole into our house into a direct current, to 15 keep the current within the cathodic protection system 16 traveling in only one direction.</p> <p>17 Q I want you to come down here. And I -- I'm 18 going to ask you to draw some things as we go through. 19 Okay?</p> <p>20 A All right.</p> <p>21 Q What's -- what is a ground bed?</p> <p>22 A A ground bed is a piece of metal that's put in 23 the ground, so that -- and designed into your cathodic 24 protection system, so that that metal is sacrificed or 25 eaten up, rather than the pipeline.</p>

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1 Q Okay. Why don't you do -- can you -- can you
2 define for the jury what cathodic protection is?
3 A Cathodic protection is an artificial means, a
4 manmade means, to prevent the metal in your pipeline
5 from being corroded away. It's a means of providing
6 metal, electrons, to the pipeline, so that the pipeline
7 itself does not deteriorate or corrode away over time.
8 Q All right. Could you --
9 MR. STEINDORF: I'm sorry, Judge. I, I
10 thought he was fixing to start drawing on this thing.
11 THE COURT: Well, I mean, I assume he
12 will. If you want to -- if you want to stand there
13 during that, that's fine. Make yourself comfortable.
14 MR. STEINDORF: If he gets to really
15 drawing a lot, I'll come back, Your Honor.
16 THE COURT: All right. Whatever suits
17 you.
18 Q (by Mr. Lyon) My next question was, would you
19 draw a rectifier, a ground bed, and then illustrate
20 cathodic protection on a pipeline for the jury?
21 A All right.
22 THE COURT: See, I think he was just
23 waiting for you to sit down to draw.
24 MR. STEINDORF: Well, I'll be back,
25 Judge.

1 away or leaving the pipeline by pushing electrons
2 toward the pipeline, so that the pipeline itself is not
3 deteriorating.
4 Q What happens if the rectifier is down or not
5 working?
6 A If the rectifier is not working, you do not
7 have this current that goes into the ground. Or if the
8 rectifier system is not working because the anode has
9 already been consumed over time, then there's no
10 material here to go toward the pipeline to prevent it
11 from corroding. And you'll have corrosion in the
12 pipeline, no rust protection.
13 Q Now, we've heard some -- or we've obviously
14 heard a little bit about pipe-to-soil readings. What
15 are those?
16 A Pipe-to-soil readings is a method of
17 determining whether your cathodic protection system is
18 working right and how effective it is. It's a method
19 of measuring the flow of current from the pipeline to
20 the soil or vice versa, so you can determine whether
21 you have a flow of electrons toward your pipe, which is
22 protecting it, or away from the pipe, which is
23 corroding it or eating it away.
24 Q Give me an example of a reading that you might
25 show or you might read if you have a pipe-to-soil

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1 THE COURT: All right.
2 (Witness complies.)
3 A First, I'm going to draw the ground, the
4 surface of the ground, and then a pipeline. This is
5 just a section of it that travels underground at this
6 point.
7 (Pause.)
8 A This device shown here is a rectifier. It
9 gets power from a power line like you see on poles, AC
10 power; converts it to direct current. There's a wire
11 from the rectifier to the anode, which is usually
12 magnesium or some other metal that's buried in the
13 ground that has some characteristics where it gives up
14 electrons when electric currents are forced through
15 it.
16 The direct current goes from the rectifier to
17 the anode, and electrons or the metal from the anode
18 goes toward the pipeline.
19 The return current is from a wire on the
20 pipeline back to the rectifier.
21 So you have a circle from the rectifier to the
22 anode through the ground and through the pipeline, back
23 to the rectifier. This positive flow of electrons from
24 the metal buried in the ground to the pipeline prevents
25 the metal on the pipeline itself from being corroded

1 reading where the pipeline is being protected.
2 A Sort of a, a minimum number that's used in the
3 industry -- we use very small numbers -- is .85 volts,
4 which would be referred to here, probably many times,
5 as 0.85 or .85.
6 So a minimum level of protection that's,
7 that's usually used in the industry -- in fact, it was
8 Koch's stated standard in this, this instance -- is to
9 have a current so that you have a major flow toward the
10 pipe of .85 volts.
11 Q All right. Write up -- write that up there.
12 (Witness complies.)
13 Q (by Mr. Lyon) Now, what would be a number
14 that someone who was trained to understand reading
15 these pipe-to-soil readings was -- what, what would you
16 find if the pipe was not being protected properly?
17 A If the pipe's not being protected properly,
18 this will be a smaller number. Instead of being
19 negative .85, it will be maybe negative .5. It will a
20 smaller negative number than this.
21 Q All right. Write up there "smaller negative
22 number".
23 A I'm just going to put .5.
24 Q Could it be .84?
25 A Yes. That would also be inadequate.

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1 So from negative .84 and a smaller number,
2 such as point -- negative .5, would be inadequate.
3 Q Okay. And the, the Code of Regulations --
4 Federal Regulations talks about adequate cathodic
5 protection, does it not?
6 A Yes.
7 Q And what are pipeline companies supposed to do
8 about cathodic protection? What is it specified that
9 they should do, in terms of protecting their pipe?
10 A Pipelines must install a cathodic protection
11 system and must monitor it to make sure that it is
12 working to protect the pipe.
13 Q Okay. And does it have to be adequate?
14 A It must be adequate.
15 Q All right. Now, and you reviewed some 4-in-1
16 reports that Koch used to work on this pipeline.
17 A Yes.
18 Q What is a 4 -- and let's write that up there,
19 4-in-1.
20 A Same sheet?
21 Q Yeah.
22 (Witness complies.)
23 Q (by Mr. Lyon) What is a 4-in-1 report?
24 A A 4-in-1 report is a record that Koch kept
25 when they dug up the pipeline and made repairs. That

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1 records the number of pieces of information, as far as
2 the condition they found and what they did to the
3 pipeline, if anything, and what -- if they put new pipe
4 in, let's say, they write down what kind of new pipe
5 and how much.
6 So it's a record of digging up, repairs, or
7 some reason repairs weren't made, if there's nothing to
8 be repaired, and what they did. They also record what
9 they found when they dug up the pipeline.
10 Q Now, let's talk about smart pigs. Okay?
11 Now, what's a smart pig?
12 A A smart pig is an electronic device that takes
13 readings remotely from inside the pipeline. And it
14 gives us a printout of data that can be used for
15 various purposes to check the condition of the
16 pipeline.
17 Q Now, how do they operate these things called
18 smart pigs?
19 A Smart pigs are pumped through the, the
20 pipeline, so that you get a remote reading of what the
21 tool is measuring while it's going through the
22 pipeline.
23 Q So if they had a smart pig go through this
24 pipe, it would -- it, it goes right through the middle
25 of it.

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1 A Yes.
2 Q And it's sending off magnetic signals?
3 A It, it -- first of all, it's centered by some
4 means. It has little, little arms to keep it, you
5 know, centered in the pipeline so you get readings all
6 around the tool.
7 And you have a -- the most common smart, smart
8 pig tool is a magnetic flux device, which usually has
9 an electronic current. It sets -- it essentially sets
10 up a magnetic current. And when you pass it through
11 the pipe, based on the readings you get back, it tells
12 you things about the condition of pipe: wall
13 thickness, if there's any places that are damaged, and
14 so forth.
15 Q Now, we have low resolution smart pigs, and
16 then we have high resolution smart pigs; is that right?
17 A Yes.
18 Q What is the difference between a low
19 resolution smart pig and a high resolution smart pig?
20 A Well, there's two differences. One, one costs
21 more money to run, the high resolution. And secondly,
22 the high resolution tool will tell you in more detail
23 what the condition or shape or any defects, anomalies
24 in the pipe look like.
25 Q All right. Let's -- you can go back and sit

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1 down.
2 (Witness complies.)
3 Q (by Mr. Lyon) Should a pipeline company rely
4 on just one safety system in order to protect one of
5 these pipelines?
6 MR. STEINDORF: Leading.
7 THE COURT: Sustained.
8 MR. LYON: I'll rephrase.
9 Q (by Mr. Lyon) How many systems of safety are
10 there on these pipelines?
11 A They have many different systems.
12 Q On how -- on this Koch system, how many
13 systems did they -- should they have had?
14 A Well, they should have had coating to protect
15 the system. And they should have had the cathodic
16 protection to, to inspect the -- to protect the system.
17 And then they also would have their other systems,
18 which would deal with monitoring pressures, how they're
19 operating the system, how they maintain it, et cetera,
20 which would be their operational and maintenance
21 systems that would go along with your pipeline.
22 Q Under the Code of Federal Regulations, are
23 pipeline companies required by law to publicly educate
24 people along their line?
25 A Yes, they are.

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1 primary protection for the pipeline system, so that it
2 lasts and it's safe.

3 **Q Let's look at -- when did Koch first record**
4 **low cathodic protection levels on this pipeline?**

5 A On their first surveys they made, their first
6 annual surveys, they record that they already had at
7 that point low cathodic protection levels that were
8 below the .85 that we were looking at a while ago.

9 MR. STEINDORF: Objection.
10 Nonresponsive.

11 Your Honor, I also want to object to, to
12 the use that's being made of this because each question
13 is leading. I can't tell whether this witness really
14 knows this information or whether he's being led by
15 this -- by this time line that's been prepared for him.
16 So this line of questioning is leading in that respect.

17 THE COURT: Okay. I'm going to overrule
18 your objection.

19 **Q (by Mr. Lyon) Now, as a pipeline safety**
20 **engineer, when you see low cathodic protection levels**
21 **recorded within one year of laying a pipeline, --**

22 THE COURT: Excuse me a second.

23 **Q (by Mr. Lyon) -- what do --**

24 THE COURT: I, I -- do you want to take
25 him on voir dire with regard to that exhibit?

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1 MR. STEINDORF: Yes, Your Honor. I will
2 take him on voir dire with respect to one -- the first
3 box.

4 VOIR DIRE EXAMINATION
5 BY MR. STEINDORF:

6 **Q Mr. Ziegler, would you pull out the documents**
7 **that you're talking about here on this first box?**

8 A Yes, sir.
9 (Witness complies.)

10 MR. STEINDORF: For the record, the, the
11 witness has shown me the deposition of Rodney Kilbourn,
12 taken February 19, 1999, and he's pointed to page 13.

13 THE WITNESS: 13 and 14.

14 **Q (by Mr. Steindorf) Did you prepare this? Did**
15 **you prepare what counsel is asking you about?**

16 A I did not prepare the presentation here.

17 **Q Who prepared this?**

18 A Someone in the attorney's office. I selected
19 materials for each tab that is on there.

20 **Q Did you lay it out like this? Did you do the**
21 **graphics?**

22 A I did not do the graphics.

23 **Q So someone in the plaintiff's counsel office**
24 **prepared this.**

25 **When did they show it to you for the first**

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1 time?

2 A About one week ago, approximately.

3 **Q Was it during the time when you were preparing**
4 **for this trial?**

5 A Yes, sir.

6 MR. STEINDORF: Your Honor, we, we would
7 object to the use of this time line in this fashion.
8 This isn't a summary of this witness's evidence about
9 the events in this case. It's a device that's being
10 used to lead him through the evidence.

11 I don't mind them going through all of
12 this and using a visual aid to summarize what the
13 witness has said. That wouldn't be objectionable. But
14 I object to the use that's being made of this in this
15 particular situation.

16 THE COURT: Okay. It's overruled.

17 DIRECT EXAMINATION RESUMED

18 BY MR. LYON:

19 **Q All right. I think I asked you, in regard to**
20 **low cathodic protection levels recorded within one year**
21 **of a pipeline, what, in your opinion, should that tell**
22 **a pipeline company who has a pipeline, such as the one**
23 **that's at issue in this case?**

24 A It would tell a pipeline company that their
25 pipeline is not adequately protected and that it is

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1 already, one year after it was put into the ground,
2 corroding or rusting away.

3 **Q As we go through the mid-80s, did you find**
4 **other places where Koch Industries had low cathodic**
5 **protection levels recorded that caused you concern as a**
6 **pipeline safety engineer?**

7 MR. STEINDORF: Leading.

8 THE COURT: Sustained.

9 THE COURT: No. You know what? I'm
10 going to overrule your objection.

11 Go ahead.

12 A Yes. I looked at a number of the surveys that
13 were taken by Koch in recording this data, as is
14 required by the Code of Federal Regulations. And on
15 many of those forms, right in the area near -- in
16 Kaufman County, near the site of this incident, a few
17 years later there were readings that were noted that
18 were below the minimum standard of .85 that's used in
19 the industry and Koch states as their standard.

20 **Q (by Mr. Lyon) And tell the jury when they**
21 **first found disbonded coating on this particular**
22 **pipeline.**

23 A As early as 1984, when some sections of the
24 pipeline were, were dug up.

25 I believe the first one they saw was perhaps

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1 where another company's pipeline was going to be
2 installed, crossing their pipeline, which was probably
3 one of the first opportunities they'd had to see the
4 pipeline, after it had been put in the ground,
5 disbonded coating or coating that was coming off or not
6 -- had, had anomalies or voids or cracks in it -- it
7 was first observed.
8 And throughout the mid 1980s, there were a
9 number of opportunities where the pipeline was dug up,
10 where this situation of the coating being damaged or
11 disbonded -- in other words, not protecting the pipe --
12 were noticed and found.
13 **Q What should Koch have done, in your opinion as**
14 **a pipeline safety engineer, when they found disbonded**
15 **coating in so many places on this pipeline?**
16 A Well, their first reaction should have been
17 immediately to increase the cathodic protection.
18 At this same time that the disbonded coating
19 was noted, they had already found that the cathodic
20 protection was inadequate. The levels were too low.
21 The first thing they should have done was to
22 immediately increase the cathodic protection. This
23 would give them reason to very carefully monitor this
24 system and to make sure that the cathodic protection
25 was increased to protect it.

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1 **Q Now, are you aware that there is another**
2 **pipeline that runs parallel to the Sterling I Pipeline,**
3 **owned by another company, through Kaufman County?**
4 A Yes. I, I call that the ARCO Pipeline.
5 **Q That's within 15 feet of this same line --**
6 A Oh, the distance --
7 **Q -- in certain places?**
8 A The distance varies. Near this site, it's,
9 it's very close.
10 **Q Actually, at the ruptured part it's only 15**
11 **feet, isn't it?**
12 A That's correct.
13 **Q Have they had any problems, according to the**
14 **National Transportation Safety Board, at all with**
15 **corrosion during the period of years that that line has**
16 **been in service in Kaufman County since 1981?**
17 MR. STEINDORF: Objection, Your Honor, to
18 relevance. We've got enough to litigate on the
19 Sterling Pipeline --
20 MR. LYON: I'm sorry.
21 MR. STEINDORF: -- without getting into
22 --
23 Objection to relevance on ARCO pipeline
24 or whatever they're talking about. It's irrelevant.
25 MR. LYON: It's -- Your Honor, it's

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1 already in the report that's been admitted into
2 evidence, number one. And the relevance is it runs --
3 there's another line, 15 feet, that has no corrosion.
4 MR. STEINDORF: I don't mind them talking
5 about it in the report, but they're not talking about
6 the report right now.
7 THE COURT: Well, your objection is
8 sustained.
9 **Q (by Mr. Lyon) In the report from the National**
10 **Transportation Safety Board, did they note that?**
11 A Yes. And I -- yes, they did.
12 And I also saw a letter --
13 MR. STEINDORF: Objection.
14 Nonresponsive.
15 THE COURT: Okay. I think it was a yes
16 or no question.
17 A Yes, they did note it.
18 **Q (by Mr. Lyon) But in the report did they note**
19 **that they had no corrosion on that line?**
20 A Yes.
21 **Q Now, in, in 1990, did -- was there an event**
22 **that occurred where they did some random digs in the**
23 **Kaufman County area?**
24 A Yes.
25 **Q And what did they, they -- how many -- what,**

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1 **what is a dig?**
2 A A dig is where you go out and purposely dig up
3 your pipeline to look at it and inspect it, to check
4 some aspect of its condition.
5 A dig is normally associated with going
6 through that procedure in several places, so you can
7 make a comparison or check something over a wider
8 geographic area.
9 **Q What did they find when they did six random**
10 **digs in Kaufman County in 1990?**
11 A They found that all six of those locations --
12 at six different locations that the coating on the
13 pipeline was disbonded or not protecting the pipeline.
14 **Q As a pipeline safety engineer, what, what does**
15 **that tell you?**
16 A That tells me that, in all probability, if
17 your primary protection of your pipeline, this tape
18 coating that was applied, has failed, then the pipeline
19 is in serious jeopardy of further problems and
20 corroding later.
21 **Q What should Koch have done at that time, in**
22 **your opinion?**
23 A In my opinion, at that time they should have
24 replaced this pipeline if they wanted to continue using
25 it.

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<p style="text-align: right;">Page 245</p> <p>1 Q Did they continue to use it?</p> <p>2 A They continued to use it for a couple of --</p> <p>3 more years at that point.</p> <p>4 And then, as we see here, they started using</p> <p>5 it again later, right before this accident.</p> <p>6 Q Now, did you review any memos from any of</p> <p>7 their corrosion supervisors or particularly a man by</p> <p>8 the name of Cary Fredrick?</p> <p>9 A Yes, sir.</p> <p>10 Q And what was his memo in 1991 about?</p> <p>11 A Mr. Fredrick's memo dealt with the seriousness</p> <p>12 of this problem, the jeopardy the pipeline was in, and</p> <p>13 he recommended that --</p> <p>14 MR. STEINDORF: Objection to hearsay. I</p> <p>15 don't believe any -- whatever memo it is that he's</p> <p>16 talking about has been introduced into evidence.</p> <p>17 THE COURT: Sustained.</p> <p>18 Q (by Mr. Lyon) Well, did you -- do you -- did,</p> <p>19 did you review his deposition, Mr. Fredrick's</p> <p>20 deposition?</p> <p>21 A Yes, sir.</p> <p>22 Q Did he talk about it, advising his company</p> <p>23 about the coating being aged and deteriorating at that</p> <p>24 deposition?</p> <p>25 A Yes.</p>	<p style="text-align: right;">Page 247</p> <p>1 this pipeline -- as it goes across Kaufman County, you</p> <p>2 see these number right here, 304, 306. Is that a mile</p> <p>3 marker? What are -- what are those?</p> <p>4 A Yeah. Those are mile markers, just like you</p> <p>5 have someplace on the interstate highway system. You</p> <p>6 start at one end and count the mileage to the other</p> <p>7 end, and you use that as reference points for your</p> <p>8 operation.</p> <p>9 Q All right. Now, where was this M8 -- where</p> <p>10 was the M8 rectifier that was down?</p> <p>11 A The M8 rectifier is near the top of the map,</p> <p>12 up at about mile point 304.</p> <p>13 Q Now, when that rectifier goes down in 1991, as</p> <p>14 a pipeline safety engineer, what, what does that tell</p> <p>15 you about what's going on with this line?</p> <p>16 A That tells you that the pipeline is in a</p> <p>17 situation where it is unprotected. The coating has</p> <p>18 failed that is your primary line of defense. And in</p> <p>19 order to maintain even the readings that -- they</p> <p>20 were -- as far as the cathodic protection, that the</p> <p>21 system is rapidly eating up the anode or the metal that</p> <p>22 was placed in the ground, so that's the pipeline's very</p> <p>23 immediate protection. And it's eating up the cathodic</p> <p>24 protection that's the second line of protection.</p> <p>25 Q Now, let's go to -- and, and let's fold this</p>
<p style="text-align: right;">Page 246</p> <p>1 MR. STEINDORF: Objection. Still, still</p> <p>2 hearsay, Your Honor.</p> <p>3 THE COURT: Sustained.</p> <p>4 Q (by Mr. Lyon) Now, in 1991, the M8 rectifier,</p> <p>5 did it go down?</p> <p>6 A Yes, sir.</p> <p>7 Q Now, what does that tell you --</p> <p>8 Now, where is the M8 rectifier?</p> <p>9 A The M8 rectifier is north of the incident site</p> <p>10 in Kaufman County. And it's, it's the next rectifier</p> <p>11 site or the first rectifier site that's upstream or</p> <p>12 north of the incident site.</p> <p>13 Q We have a map here of Kaufman County I'll put</p> <p>14 over here.</p> <p>15 THE COURT: Go ahead.</p> <p>16 MR. LYON: I'm sorry.</p> <p>17 THE COURT: It's fine. No. Really, it's</p> <p>18 fine.</p> <p>19 Q (by Mr. Lyon) All right. The rupture site</p> <p>20 on this particular -- on where Lively and where the</p> <p>21 Oak, Oak Circle is, is right down here; is that right?</p> <p>22 A Yes. On, on pipelines that are marked by</p> <p>23 milepost, that's about at the 330 milepost or 331</p> <p>24 milepost.</p> <p>25 Q All right. Now, these, these numbers here on</p>	<p style="text-align: right;">Page 248</p> <p>1 up for a minute so the jury can --</p> <p>2 THE COURT: No. I'm -- no. Really, if</p> <p>3 you're -- if you're going to use it in your</p> <p>4 presentation --</p> <p>5 MR. LYON: I am, but I'm --</p> <p>6 THE COURT: Just, just leave it. It's</p> <p>7 fine. Or prop, prop it up in the corner.</p> <p>8 MR. LYON: Okay.</p> <p>9 THE COURT: It's not going to -- I</p> <p>10 imagine before this trial's over with, the jury's going</p> <p>11 to be sick enough of seeing me. Let them look at the</p> <p>12 map.</p> <p>13 MR. LYON: Okay.</p> <p>14 Q (by Mr. Lyon) Okay. Let's go to -- now,</p> <p>15 they, they take this line out of service in 1993; is</p> <p>16 that right?</p> <p>17 A Yes.</p> <p>18 Q And then they -- what did they do with it from</p> <p>19 '93? I mean, could you find any evidence of protecting</p> <p>20 it cathodically in '94?</p> <p>21 A I find no evidence from the reports or the</p> <p>22 depositions that they improved the cathodic protection</p> <p>23 or tried to correct the cathodic protection situation</p> <p>24 during that time.</p> <p>25 Q Now, let's go to -- they decided to bring this</p>

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1 line back up, did they not?

2 A Yes.

3 Q Okay. And when did they -- when they brought

4 it -- well, do you know -- do you know when they

5 brought it back up or when they started working on

6 bringing it back in service?

7 A Well, they, they -- let's see. It was -- it

8 was two stages. They -- you know, approximately 1993

9 or '94. And I think even internally, in all fairness

10 to Koch, this is a little foggy on exactly when that

11 process started. But somewhere in 1993 or '94 they

12 started through the process of planning to return the

13 pipeline to service.

14 Q Now, based on your personal -- do you have an

15 opinion if, if they should have operated this line at

16 all after '93? Do you have an opinion?

17 A Yes, I do.

18 Q And what is that opinion?

19 A My opinion is, based on the failure of their

20 primary system of coatings and based on the cathodic

21 protection problems they had noted, starting the first

22 year the pipeline was in operation, that they should

23 not have returned it to service.

24 Q At all?

25 A At all.

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1 Q Would a reasonably prudent operator have

2 returned it to service, in your opinion?

3 A In my opinion, they would not. The protection

4 is gone, and they, they should not and would not have

5 returned it to service.

6 Q Okay. Now, do you know why they returned it

7 to service, from an economic standpoint, based on your

8 review of the records?

9 A Yes.

10 Q Why?

11 A They returned it to service because primarily

12 with -- what they could do with product by storing it,

13 selling it, trading it, et cetera down in the Mont

14 Belvieu area, which is the end terminal of the pipeline

15 where all of these other facilities and activities are

16 located that I was talking about before, they would --

17 they decided that they could take their Medford,

18 Oklahoma storage out of service and use more fully

19 opportunities down in the Mont Belvieu area.

20 In order to do that, they needed to increase

21 capacity and to be able to move the product through

22 this Sterling I system down to Mont Belvieu.

23 Q So how much money are we talking about?

24 A According to a document, I think, from Mr.

25 Elmore's file, a Koch employee, initially by taking the

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1 Medford storage out of service and fees, they would

2 earn 10 million dollars the first year. And then, as

3 the pipeline operated, they projected they would make a

4 profit of almost 8 million dollars a year for the next

5 15 years by putting this pipeline back in service.

6 Q Even though, in your opinion, this was a

7 dangerous pipeline.

8 A In my opinion, yes.

9 Q All right. Now, in '95 we found that M9, this

10 rectifier that's located very close to the rupture

11 site -- what records did you find in regard to that M9

12 rectifier?

13 A Starting in this time frame, the mid 1990s,

14 about -- at least a year before -- over a year before

15 this incident, they noted that the M9 rectifier was

16 being depleted. From the readings on the rectifier

17 they could tell that the anode or ground bed there was

18 also fast becoming used up and would soon be useless.

19 Q Now, the M9 rectifier on this map is located

20 right here (indicating); is that right?

21 A That's, that's correct.

22 I misspoke a minute ago. It's the closest one

23 to the site. The M8 is further north.

24 THE REPORTER: Can you repeat that,

25 please, sir?

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1 THE WITNESS: The M8 is further north.

2 Q (by Mr. Lyon) And, and this is the rectifier

3 that provides cathodic protection for the actual

4 rupture site; is that right?

5 A That's correct.

6 Q Now, Koch did some hydrostatic tests on this

7 line after 19- -- well, about -- they started

8 hydrostatically testing this line on -- April of '95;

9 is that right?

10 A Yes, sir.

11 Q Would you tell the jury what a hydrostatic

12 test is?

13 A A hydrostatic test, in this case, was to fill

14 the pipeline with water and pressure up on the pipeline

15 to a certain pressure to determine if it would hold

16 that pressure.

17 Q And did the line fail?

18 A Yes, the line failed at a pressure less than

19 what they intended to test it to, what they intended to

20 operate its pressure at.

21 Q And did, did it fail in Kaufman County?

22 A Yes.

23 Q Do you know what -- exactly in what area?

24 A Well, it, it was -- what they were then

25 calling the test site, which was just a few miles north

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1 of the rupture site, somewhere up around milepost 314
 2 or somewhere in, in that area, not too far north of
 3 this.
 4 **Q Well, as a pipeline safety engineer, what does**
 5 **that tell you? Or what would -- what does that tell**
 6 **you about what's going on with this line in '95, when**
 7 **you have the line bursting in two spots when they do**
 8 **the hydrostatic test?**
 9 **A This tells me, especially when we see the**
 10 **pressure that the line burst at, which was less than**
 11 **the original design pressure -- it tells me that the**
 12 **coating failure that we've seen and the cathodic**
 13 **protection failure that we've seen have actually**
 14 **allowed the pipeline to seriously deteriorate to where**
 15 **it would not even hold its original design pressure.**
 16 **Q Now, what if somebody says, "Well, you know,**
 17 **Mr. Ziegler, it burst in one spot. But the rest of the**
 18 **line -- it's pretty thick. What do -- what do you say**
 19 **to that? So why don't we just cut up this little piece**
 20 **here and take it out and just patch it up?"**
 21 **A Well, that's a good question. And if -- and**
 22 **if, if a pipeline bursts while you're testing it or**
 23 **while you're operating it, it's usually going to burst**
 24 **in one spot. So it's going to burst at the place where**
 25 **it was the weakest.**

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1 Now, the problem is if you know you have a
 2 weak spot, -- once you have a pipeline that ruptures or
 3 bursts, you know you have a problem. The next trick is
 4 to know -- to determine how confident you are or what
 5 basis you have for determining if that was the only
 6 place where the pipeline was weak.
 7 Koch then went through a series of, of tests,
 8 such as a smart pig, to look for anomalies or other
 9 problems in the pipeline, to start determining what the
 10 actual overall condition of this pipeline was.
 11 **Q And that was in '95. In, in 5-19 of '95?**
 12 **A Yes.**
 13 **Q And what did that show in the area that we're**
 14 **talking about, where this rupture occurred?**
 15 **A The survey that was taken with this smart pig,**
 16 **the tool that's put through the pipeline, located**
 17 **approximately 583 anomalies.**
 18 **Q Now, let's, let's talk English here.**
 19 **What's an anomaly?**
 20 **A Well, it's a -- it's a defect where the**
 21 **pipeline was between -- had between 15 percent and 50**
 22 **percent or more of the wall that was thin or corroded**
 23 **away. In other words, a defect in the pipe.**
 24 **Q Now, what did Koch do in regard to these 583**
 25 **locations of, of corrosion in Kaufman County above 15**

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1 **percent? We're not talking about those areas of**
 2 **corrosion below 15 percent.**
 3 **They actually found hundreds of those, did**
 4 **they not?**
 5 **A Yes, sir.**
 6 **Q And what did they do in regard to those 583?**
 7 **A With regard to the 583, they decided to fix**
 8 **some of those. They picked what they called severe or**
 9 **moderate corrosion, which was above 30 percent, and**
 10 **decided to dig up and fix those.**
 11 **Q Now, they ran a second hydrostatic test.**
 12 **What, what do you -- what do you --**
 13 **First of all, what should they have done after**
 14 **they found this 583 locations where it's -- this pipe**
 15 **has corroded 15 percent or more in 1995? What should**
 16 **they have done, in your opinion?**
 17 **A Well, at that time they had a condition -- and**
 18 **they documented this themselves -- which is known as a**
 19 **pipeline safety condition, which means that you must**
 20 **either fix the pipeline or take it out of service or**
 21 **downgrade your operating pressure to find a safe**
 22 **pressure at which you can operate the pipeline that is**
 23 **less than the designed pressure.**
 24 **Q Did Koch do any of those?**
 25 **A Well, Koch made an effort to fix the pipeline**

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1 by repairing some of the anomalies.
 2 **Q Should they have -- assuming that they knew**
 3 **all of these things that we've gone through before,**
 4 **should they have operated this pipeline at all after**
 5 **8-3 of '95, once they did this 583 -- found 583**
 6 **corrosion spots in Kaufman County?**
 7 **MR. STEINDORF: Objection. Assumes facts**
 8 **in -- not in evidence.**
 9 **The witness has already explained that**
 10 **there wasn't anything going through the pipeline in**
 11 **'95, so the question is misleading. It was out of**
 12 **service in '95.**
 13 **MR. LYON: Well, I -- the question was**
 14 **after '95, should they have operated it at all.**
 15 **MR. STEINDORF: If I misunderstood the**
 16 **question, I apologize.**
 17 **THE COURT: Okay. Go ahead.**
 18 **A No. They should -- they should not have**
 19 **operated the pipeline because of other things they**
 20 **found at this time.**
 21 **After they pressure-tested the pipeline, they**
 22 **then, then dug up some other areas and found that even**
 23 **though the pipeline had withstood the test pressure,**
 24 **they found areas after the test where there was as much**
 25 **as 85 percent of the pipeline wall missing. They then**

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1 replaced some pipe in, in some of those areas that they
2 decided to dig up and identify.
3 But then they went ahead, in spite of knowing
4 that information, and put the pipeline back in
5 operation in 1996.
6 **Q (by Mr. Lyon) Have you ever seen Swiss**
7 **cheese?**
8 A Yes.
9 **Q Is this pipe -- the sort of pipeline running,**
10 **running through Kaufman County back then about like**
11 **Swiss cheese?**
12 A That would be an industry expression that's
13 used for a pipeline that's very severely corroded.
14 This is what's called general corrosion, which means
15 it's not just one spot where you may have had a stray
16 current from another structure or another electrical
17 device or something like that.
18 There were -- there were -- there were
19 hundreds and thousands over the -- this area of the
20 pipeline of places where it was corroded. In the
21 industry that would be called Swiss cheese, which means
22 essentially the pipeline is gone.
23 **Q Now, did you review a dig report from --**
24 **concerning a Mr. Don Carson from 8-28-95?**
25 A Yes.

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1 **Q What did you find there?**
2 A The pipeline was dug up. This is one of the
3 digs after the pipe had been pressure-tested, and that
4 was a defect found of, of more than 30 percent right
5 near where this pipeline incident occurred.
6 That confirmed that that also -- Koch knew at
7 that time that there was bad pipe in that area.
8 **Q Now, the rectifier M9 -- when did it finally**
9 **just fail?**
10 A The M9 rectifier, the closest one to the
11 incident site, failed and was out of service in the
12 fall of 1995, before Koch put the pipeline back in
13 service.
14 They already knew that where this incident
15 occurred, there was no cathodic protection on the
16 pipeline before they put it back in service. The
17 protection was gone, yet they went ahead and put it in
18 service.
19 **Q Is that a violation of the federal law?**
20 A Yes, it is. It's a violation of the Code of
21 Federal Regulations to operate a pipeline when you know
22 it's not adequately protected.
23 **Q In your opinion, did they do that?**
24 A Did they --
25 **Q -- operate a pipeline without adequate**

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1 **cathodic protection in the area where Danielle Smalley**
2 **was killed?**
3 A Yes. They, they -- from all of their own
4 documents, they knew it was not protected and they knew
5 the coating had failed.
6 **Q So they made a conscious decision, is what**
7 **you're telling the jury.**
8 A Yes.
9 **Q Let's go to when they reopened the line.**
10 **Did they find low cathodic protection from**
11 **Terrell to Lively?**
12 A Yes. In the spring of 1996, early spring when
13 they put the line back in operation, they continued in
14 the Kaufman County area to see readings that were below
15 the .85. It was not adequately protected by industry
16 standards or by their own criteria when they put the
17 pipeline back into operation and were operating.
18 **Q Now, they tried to fix M9, did they not? And**
19 **then it, it failed again.**
20 A Yes. They went through a, a process of
21 recognizing and making decisions, both to try to fix
22 this cathodic protection area and also to add
23 additional cathodic protection. But that process was
24 never completed, so that they had cathodic protection
25 that was adequate and working, before the incident.

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1 **Q Now, do the records reveal that, that M9**
2 **finally just crashed down in, in March -- excuse me --**
3 **in March of '96?**
4 A Yes. In March of '96. By that time, M8 had
5 failed, 8.5 had failed, and 9 had failed, so that all
6 of the cathodic protection rectifiers that were in the
7 area north of and near the incident site -- Koch knew
8 at that time that they were out of service.
9 In addition to having known about the
10 disbonded coating problems, they knew by this time that
11 for a number of years there had not been adequate
12 protection with the proper readings on this section of
13 the pipeline.
14 **Q And did they continue to operate this pipeline**
15 **from March, April, May, June, July, and August without**
16 **cathodic protection?**
17 A Yes. They were putting a thousand barrels an
18 hour through it at about 1,000 pounds in this area
19 during that whole time.
20 **Q And it went all the way up until the date that**
21 **it ruptured and killed Danielle Smalley and Jason**
22 **Stone.**
23 A That's --
24 **Q Is that right?**
25 A That's correct.

Page 21

1 Q (by Mr. Lyon) Do you recall your testimony
2 Friday about Cary Fredrick?
3 A Yes.
4 Q And what was your testimony about Cary
5 Fredrick?
6 A Cary Fredrick said in his deposition that it
7 was widely known among Koch management and Koch
8 personnel that there were coating problems on the
9 Sterling I Pipeline, Pipeline and that those were
10 caused by, among other things, the pipeline being laid
11 in wet conditions.
12 Q I'll show you what's been marked as
13 Plaintiff's Exhibit No. 34 and ask you if you can
14 identify that.
15 A Yes, I can.
16 Q What is that?
17 A This is one of the 4-in-1 reports identified
18 as dig number P, letter P, which was performed in
19 August of 1995.
20 Q And also Plaintiff's Exhibit No. 36. What is
21 that?
22 A 36 is another 4-in-1 report of a dig where
23 they dug up the pipeline. This is dig B, letter B, as
24 in boy, which is August 22nd, 1995.
25 Q You're talking about this is a -- these are

Page 22

1 records from Koch Industries?
2 A Yes.
3 Q Okay.
4 MR. LYON: We'll offer into evidence
5 Plaintiff's Exhibit 35 and 36.
6 MR. STEINDORF: I'm assuming he means 34
7 and 36.
8 MR. LYON: I have another one that's --
9 yeah. 34 and 36. Excuse me.
10 MR. STEINDORF: No objection to 34 and
11 36.
12 THE COURT: They're admitted.
13 (Plaintiff's Exhibits Nos. 34 and 36
14 admitted.)
15 Q (by Mr. Lyon) Now, Mr. Ziegler, come down
16 here, please. I want to ask you some questions about
17 this.
18 MR. LYON: Down a little more. No, just,
19 just a little smaller. Okay. There you go. Okay. Up
20 a little bit. It's hard to see. Can you enlarge it
21 just a bit? Okay.
22 Q (by Mr. Lyon) Now, this is a -- they call it
23 pipeline revision report?
24 A Yes. This is the 4-in-1 report. It has
25 aerial, foreign crossing, exposed pipe, --

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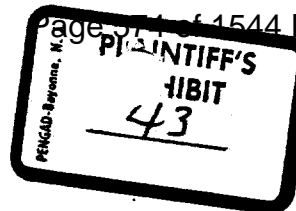
1 THE REPORTER: Excuse me. Speak up,
2 please.
3 A This is a 4-in-1 report. It has aerial,
4 foreign crossing, exposed pipe, or pipeline revision
5 report. It's information on a situation where Koch
6 digs up and for some reason examines their pipe. They
7 may make repairs; they may not. But this document is
8 what they found when they dug up their pipeline.
9 Q (by Mr. Lyon) And what is the date of that
10 document?
11 A The date's right there. I think it's 8/22.
12 Q '95?
13 A '95.
14 Q You might have to step back.
15 A Oh, okay.
16 Q Okay. Now, what is the significance of this
17 document? First of all, where, where was this done?
18 What county was it?
19 A This is in Kaufman County. And it's on the
20 section of line between the test station and Corsicana.
21 So it's on the section of pipeline that would be across
22 what's involved in this incident.
23 Q And the mile post is 319, so it's pretty close
24 to the rupture site?
25 A Right. It would be about 11 miles from the

Page 24

1 rupture site.
2 Q Okay. Now, what is the significance of this
3 document to you?
4 A The significance of this document to me is
5 that in July of 1995, one month before this pipeline
6 was dug up, we have the documents. We were just
7 looking at the exhibits that are the -- our so-called
8 test report for the hydrostatic test on that pipeline,
9 which says that that pipeline held pressure for 1800
10 psi or 1800 pounds.
11 One month later the pipeline was actually dug
12 up and looked at by Koch, and they find a pit on this
13 pipeline that is holding 160, which 160 mils is 85
14 percent through the wall of this pipe.
15 So this tells Koch not only that you cannot
16 use a hydrostatic test to tell you if your pipeline is
17 correct and safe, but they knew when they dug this up
18 that there was a pit that was 85 percent through the
19 wall of this pipe. Only about 30-thousandths of an
20 inch were left on this particular piece of pipe, and it
21 had withstood a hydrostatic test.
22 Q Do you have a measurer with you --
23 A Yes, I do.
24 Q -- to show the jury what 30-thousandths of an
25 inch is?

30

INTER-COMPANY MEMO



DATE October 1, 1990

TO Ken Dayton

FROM Roger Floyd

SUBJECT CATHODIC PROTECTION PROBLEMS ON STERLING

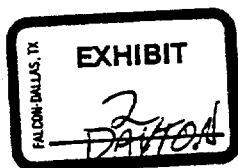
After conducting extensive testing on the Sterling Line the corrosion department has established that the reason for the drop in our cathodic protection levels is a deterioration of the coating on both lines. We excavated six (6) areas on the Sterling Line and found the coating to be totally disbonded from the pipe. The tape also had, in two (2) cases, mechanical damage from the time of installation.

In September 1990, we installed a conventional groundbed and cathodic rectifier on the north side of highway 85 in Kaufman County, Texas. I felt this rectifier would protect the approximately twenty-five (25) miles of low potential. It brought twelve (12) miles to protected levels. Further examination has shown that the bulk of the bad coating is from highway 31 to farm to market road 636. We have installed I.R. test stations in this area and can find no evidence of interference.

Since 1985, we have installed three (3) additional rectifiers on the Sterling Line from the Red River to Corsicana Station. This is a direct result of coating deterioration on the system.

I recommend the installation of one (1) cathodic protection system of at least a forty (40) amper capacity on the line and the addition of one (1) system of at least twenty-five (25) amper capacity on the Chico Line near the four to six trap. These units should provide ample current to provide protection to the lines for the future. I further propose to conduct close interval surveys of these areas to pin point areas where recoating would be of the most benefit.

RF/jl



KP/B 075881

31

25	25	Pipeline Revision	148	149
25		Report		

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1 right?

2 MR. WOLF: Objection, Your Honor,

3 leading.

4 THE COURT: Sustained.

5 MR. KRUMHOLZ: Pass the witness.

6 MR. WOLF: Nothing further. Nothing

7 further.

8 THE COURT: Thank you, sir, you may step

9 down.

10 How are we feeling in there? Break time. Do

11 you want a ten- or fifteen-minute break?

12 All right. Be back in fifteen minutes.

13 (Recess taken.)

14 (Jury ushered in.)

15 THE COURT: Be seated, please.

16 Call your next witness.

17 MR. McCAULEY: Your Honor, our next

18 witness is Mr. Charles Powell. He is alive, hopefully.

19 In person. Alive and in person, we hope.

20 THE COURT: Sir, you weren't sworn

21 earlier, were you?

22 THE WITNESS: No, sir.

23 THE COURT: Raise your right hand.

24 (Witness sworn.)

25 THE COURT: All right. Be seated,

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1 please.

2 THE WITNESS: Thank you.

3 CHARLES WAYNE POWELL,

4 having been first duly sworn, testified as follows:

5 DIRECT EXAMINATION

6 BY MR. McCAULEY:

7 Q State your name, please.

8 A Charles Wayne Powell.

9 Q What is your occupation, Mr. Powell?

10 A I am a metallurgical engineer by training, but

11 the job I do is called failure analysis.

12 Q And you have been engaged in this case by the

13 plaintiffs to assist in doing what?

14 A Well, I was contacted by the plaintiff to

15 examine the particular piece of pipe that ruptured in

16 the accident and to determine basically its cause of

17 failure; why it ruptured.

18 Q Okay. Would that pipe be somewhere near you

19 right now? Is that Plaintiff's --

20 A Yes, sir.

21 Q -- Exhibit --

22 A This is it.

23 Q -- No. 1?

24 A Yes, sir. This is it. This is it right here

25 (indicating).

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1 Q And you've seen that pipe before today; is

2 that correct?

3 A I have.

4 Q Where did you last see that pipe?

5 A I last saw that pipe in Medford, Oklahoma in

6 March of 1999.

7 Q All right. And tell the jury, if you would,

8 please, what you've done as part of the process of

9 review and work in this case. Just kind of go over

10 what all in a general way that you've done as part of

11 your work in this case.

12 A Well, in general, besides examining the piece

13 of pipe, I went to the accident scene in September of

14 1996; took some photographs of the area in which the

15 accident happened.

16 I was asked to review a large volume of

17 documents and materials that were provided by Koch, the

18 defendant in this case, to examine and evaluate the

19 type of corrosion protection that the pipeline had

20 received. I additionally looked at other segments of

21 the pipe that came out of the ground adjacent to this

22 piece, about 15 other pieces. And I reviewed, as I

23 said, a great number of documents.

24 I also was -- attempted to look at other

25 sections that had been removed from the ground, from

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1 the Sterling I Pipeline. But they were unidentified

2 and simply piled in heaps, so there wasn't very much we

3 could tell from them.

4 Q Let me step back a second and ask you now, to,

5 having described who you are and what you are, tell the

6 jury how you became what you are.

7 If you would, go through your educational

8 background and give me some idea of what kind of

9 training you have educationally.

10 A All right. I have a Bachelor's of Science in

11 metallurgical engineering from the University of

12 Oklahoma. I received that in 1974.

13 After I graduated from college, I went to the

14 Army for active duty for three years with the Corps of

15 Engineers. I got an honorable discharge from the Army,

16 went back to graduate school for a year, and then left

17 to join the Department of Defense to do aircraft

18 failure analysis at the Physical Sciences Laboratory

19 there in Oklahoma City.

20 I was there for one year and was enticed into

21 private practice by two other engineers. We formed,

22 formed a company called InTech Corporation. And I

23 worked there for ten years, doing failure analysis for

24 different companies, as well as for work that also is

25 going to go to court.

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1 pretty high.
2 Q All right. Now, we've moved down the road
3 until 1990. And now, in addition to what you've told
4 us about up to 12-85, we have three different accounts
5 by employees where they referenced disbonded coating,
6 particularly in this area around here (indicating).
7 And then the six random digs where there was totally
8 disbonded coating.
9 Let me ask you if you have an opinion as to
10 what a reasonable and prudent pipeline operator ought
11 to have done by 1990, when that information was found
12 after those six digs?
13 A Well, you know then that the one key element
14 of your protection for this pipeline is compromised.
15 That's the coating.
16 Now, there are a lot of pipelines that have
17 been installed in ages past that don't have a very good
18 coating or never had a very good coating. They just
19 require an awful lot of cathodic protection. And this
20 may be related to -- the fact that the cathodic
21 protection values were dropping may mean that the
22 coating had been totally compromised in a lot of areas,
23 hence, requiring more and more current output from the
24 cathodic protection system.
25 Q What should Koch have known from the

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1 accumulated red flags that you've shown us there up to
2 1990?
3 A They should have known that active corrosion
4 was proceeding in the pipeline.
5 Q Is there any question in your mind, any doubt
6 at all, that they should have been aware of that?
7 A None.
8 Q Is active corrosion -- well, strike that.
9 You're familiar, we referred earlier, with the
10 CFRs, aren't you?
11 A Yes.
12 Q We've had -- go ahead and take your seat for
13 just a second. Have, have a seat for just a second.
14 Are you familiar with what is the standard
15 which must be met by a pipeline operator, with regard
16 to cathodic protection on a pipeline? What is the --
17 what do -- what do they have to do?
18 A Well, generally the CFRs say that corrosion
19 has to be -- the corrosion protection system has to be
20 -- it has to be an adequate corrosion protection system
21 to keep corrosion from occurring on a pipeline.
22 Q An adequate corrosion protection system to
23 mitigate or keep corrosion from occurring?
24 A Correct.
25 Q And we had a witness testify a little earlier

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1 today that said to keep the -- to keep the pipeline so
2 it can be operated safely. Would you agree with that?
3 A Yes, sir.
4 Q In 1990, by the time they did those six digs,
5 was, in your opinion, the cathodic protection on
6 Sterling I adequate?
7 A Well, based on the fact that the readings keep
8 going low and that we're finding a lot of disbonded
9 coating, in my opinion, the corrosion protection system
10 would not be adequate, as the records are showing.
11 Q Well, and the bottom line question, I guess,
12 is -- was it mitigating corrosion at that point by all
13 the evidence available?
14 A No.
15 Q All right. Where is the next point where you
16 find a red flag ought to be placed?
17 A Well, the next entry on our time line is the
18 observation in the records that one of the rectifiers,
19 M8, was totally out of -- out of use then.
20 Q All right. Do you understand M8 to be in
21 close proximity to where the ultimate rupture occurred
22 in 1995 --
23 A Yes.
24 Q -- 1996?
25 A Yes.

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1 Q Okay. So M8 was down completely.
2 A Correct.
3 Q When is the next major red flag?
4 A Well, when it's down, there's absolutely zero
5 cathodic protection. And we know that there are
6 coating ruptures, so we know for a fact that active
7 corrosion's occurring at that point.
8 Q All right.
9 A In 1991, Cary Fredrick, a corrosion technician
10 for Koch, told them in his report that the coating was
11 aged and deteriorating.
12 Q And do you understand that he was the actual
13 corrosion supervisor for Sterling I at the time he
14 wrote that report?
15 A I believe that's correct.
16 Q All right.
17 (Off-the-record discussion.)
18 Q (by Mr. McCauley) Now, you're saying that Mr.
19 Fredrick by memo told James Elmore, Koch's
20 representative, about this?
21 A I believe that's correct.
22 Q Let me ask you to look at what's been marked
23 as Exhibit 62 in this trial, and tell me if you
24 recognize that.
25 A Yes. This is the memo from Mr. Fredrick to

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1 Chris Wilkins and Jim Elmore.

2 **Q All right. And what is he advising them in**
3 **that memo.**4 MR. STEINDORF: Before, before they go
5 into reading the exhibit, Your Honor, it ought to be
6 offered.7 MR. McCAULEY: Your Honor, at this point
8 we would offer into evidence Plaintiff's Exhibit 62.

9 MR. STEINDORF: One moment.

10 THE COURT: Sure. That's fine.

11 How are we doing up here? Everybody
12 okay? Do you have an hour left in you?13 MR. STEINDORF: May we approach, Your
14 Honor?

15 THE COURT: Yeah. Okay.

16 MR. STEINDORF: Thank you.

17 THE COURT: Do you -- do you -- do you
18 need a break really? Yeah. Okay. Then five minutes.

19 (Jury exited courtroom.)

20 (Conference at the bench.)

21 THE COURT: Okay. Mr. Powell, for the
22 record, let me just reflect to you that the Rule has
23 been invoked in this case. And what that means, that
24 until you're released as a witness, you are
25 specifically instructed that you can't discuss this

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1 case among anyone -- with anyone, with the exception of
2 the lawyers, if that's your desire to do so. You can't
3 discuss it with third parties. And that will include
4 the working press.

5 All right, sir?

6 THE WITNESS: Yes, sir.

7 THE COURT: Okay.

8 (Jury ushered in.)

9 THE COURT: All right. Thank you. Be
10 seated.

11 Go ahead, sir.

12 MR. McCAULEY: Thank you, Your Honor.

13 **Q (by Mr. McCauley) Mr. Powell, --**14 MR. McCAULEY: And, Your Honor, I'm going
15 to withdraw the offer of Exhibit 62. By agreement of
16 the counsel, we're going to just read a portion out of
17 this.

18 THE COURT: Okay.

19 **Q (by Mr. McCauley) Mr. Powell, I'd ask you**
20 **just to read out of that letter that we talked about**
21 **earlier, which was from -- to Chris, Chris Wilkins and**
22 **Jim Elmore from Cary Fredrick --**23 **Just read the portion that I've bracketed**
24 **there, please.**

25 A "I feel we can expect a greater increase in

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1 current requirement, increase south of the Red River to

2 Corsicana, based on records of this section of line.

3 Again, our awareness of the inspection procedures, or
4 lack of, on this section of line."5 **Q Thank you, sir.**6 **Now, let me ask you again to turn your**
7 **attention to -- and you just brought that one up, that**
8 **letter, when you were dealing with an entry --**9 **Which entry were you referring to when you**
10 **brought that up, Mr. Powell?**11 A That's -- that reading was from the last
12 entry, Cary Fredrick's memo to his boss, James Elmore.13 **Q In 1991, in September?**

14 A Correct.

15 **Q Okay. What is the next point at which you**
16 **believe a red flag should be placed, based upon your**
17 **work?**18 A Well, the next point would be the continuation
19 of the line here.20 **Q So we'll continue, then, the line to the next**
21 **board, which goes clear to 3/2/95, I believe. Starting**
22 **on -- you believe on that time line, starting at that**
23 **point, a red flag should be placed.**24 A Well, a memo was placed up here that really is
25 not a, a document showing degradation of the corrosion

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1 detection system but more is a -- is a employment issue
2 requirement of getting more inspections on the line.
3 But it's basically a memo that was assessed by Mr.
4 Taylor, talking about the understaffing in the
5 corrosion department.6 **Q If that's not a red flag, let's skip to the**
7 **next one that is a red flag, where they should have**
8 **been on notice of the impending disaster that was going**
9 **to occur on August 24th, 1996.**10 A Well, in 1995 several things occurred that
11 kind of brings us up to the culmination of the
12 uncovering of the fact that there's a severe amount of
13 corrosion in this pipeline.14 David Kilian discusses that corrosion problems
15 are occurring from Farmersville to Corsicana. The --
16 another rectifier bed is dying, M9, which is just on
17 the other side of where the actual explosion happened.
18 Remember, M8 had lost its bed earlier. Now M9 is
19 dying, and they want to bring this part of the line
20 back into service in 1995.21 So they conduct a hydrostatic test. And that
22 hydrostatic test ties two areas where corrosion has
23 occurred all the way through the pipeline to such an
24 extent that it caused a rupture in the pipeline.25 **Q And that's the one you referred to while ago**

32

<div>REPORTER'S RECORD</div> <div>VOLUME 5 OF 24 VOLUMES</div> <div>TRIAL COURT CAUSE NO. 51458</div> <div>DANNY SMALLEY, INDIVIDUALLY) IN THE DISTRICT COURT</div> <div>AND AS INDEPENDENT)</div> <div>ADMINISTRATOR OF DANIELLE)</div> <div>DAWN SMALLEY, DECEASED)</div> <div>VS.) KAUFMAN COUNTY, TEXAS</div> <div>)</div> <div>KOCH INDUSTRIES, INC., KOCH)</div> <div>PIPELINE COMPANY, L.P.,)</div> <div>KOCH HYDROCARBON COMPANY,)</div> <div>KPL/GP, INC., AND RONALD)</div> <div>GANT) 86TH JUDICIAL DISTRICT</div> <div>TRIAL ON MERITS</div> <div>On the 7th day of October, 1999, the following</div> <div>proceedings came on to be heard in the above-entitled</div> <div>And numbered cause before the Honorable Glen M.</div> <div>Ashworth, Judge presiding, held in Kaufman, Kaufman</div> <div>County, Texas:</div> <div>Proceedings reported by machine shorthand.</div>	<div>Page 3</div> <div>1 WITNESS INDEX</div> <div>2 Voir</div> <div>3 Direct Cross Redirect Recross Dire</div> <div>4 DANNY 6</div> <div>5 ROBERT 14</div> <div>6 KARA</div> <div>7 SHORT 29</div> <div>8 JAMES</div> <div>9 CRADDOCK 46 58</div> <div>10 MARY</div> <div>11 CRUTCHFIELD 64</div> <div>12 TIMOTHY</div> <div>13 THORP 93 103</div> <div>14 MELANIE</div> <div>15 MAYFIELD 111 129</div> <div>16 DANIEL</div> <div>17 MAYFIELD 130 152</div> <div>18 JAMES</div> <div>19 TUCKER 154 189</div> <div>20 EDWARD</div> <div>21 ZIEGLER 203 222</div> <div>22 222 238</div> <div>23 239</div> <div>24 ALPHABETICAL WITNESS INDEX</div> <div>25 Voir</div> <div>Direct Cross Redirect Recross Dire</div> <div>1 JAMES</div> <div>2 CRADDOCK 46 58</div> <div>3 MARY</div> <div>4 CRUTCHFIELD 64</div>
<div>Page 2</div> <div>1 APPEARANCES</div> <div>2</div> <div>3 Mr. Ted B. Lyon</div> <div>4 SBOT NO. 12741500</div> <div>5 Mr. Marquette Wolf</div> <div>6 SBOT NO. 00797685</div> <div>7 TED B. LYON & ASSOCIATES</div> <div>8 Town East Tower - Suite 525</div> <div>9 18601 LBJ Freeway</div> <div>10 Mesquite, Texas 75150</div> <div>11 Phone: (972)279-6571</div> <div>12 ATTORNEYS FOR PLAINTIFF</div> <div>13 -AND-</div> <div>14 Mr. R. Michael McCauley</div> <div>15 SBOT NO. 13383500</div> <div>16 McCAULEY, MACDONALD, DEVIN & HUDDLESTON</div> <div>17 3800 Renaissance Tower</div> <div>18 Dallas, Texas 75270-2014</div> <div>19 Phone: (214)744-3300</div> <div>20 ATTORNEY FOR PLAINTIFF</div> <div>21 -AND-</div> <div>22 Mr. Michael C. Steindorf</div> <div>23 SBOT NO. 19134800</div> <div>24 Mr. Richard S. Krumholz</div> <div>25 SBOT NO. 00784425</div> <div>Mr. Sean P. Brennan</div> <div>SBOT NO. 00787135</div> <div>FULBRIGHT & JAWORSKI</div> <div>2200 Ross Avenue, Suite 2800</div> <div>Dallas, Texas 75201</div> <div>Phone: (214)855-8022</div> <div>ATTORNEYS FOR DEFENDANTS</div>	<div>Page 4</div> <div>1 ALPHABETICAL WITNESS INDEX, CONT.</div> <div>2 Voir</div> <div>3 Direct Cross Redirect Recross Dire</div> <div>4 DANIEL</div> <div>5 MAYFIELD 130 152</div> <div>6 MELANIE</div> <div>7 MAYFIELD 111 129</div> <div>8 ROBERT</div> <div>9 MEHL 14</div> <div>10 DANNY</div> <div>11 MILLS 6</div> <div>12 TIMOTHY</div> <div>13 THORP 93 103</div> <div>14 JAMES</div> <div>15 TUCKER 154 189</div> <div>16 EDWARD</div> <div>17 ZIEGLER 203 222</div> <div>18 222 238</div> <div>19 239</div> <div>20 EXHIBIT INDEX</div> <div>21 PLAINTIFF'S DESCRIPTION OFFERED ADMITTED</div> <div>22 NO.</div> <div>23 20 Curriculum Vita 16 17</div> <div>24 of Dr. Mehl</div> <div>25 21 Letter Written 38 38</div> <div>26 by Danielle Smalley</div> <div>27 22 Photos of 41 41</div> <div>28 Danielle Smalley</div> <div>29 23 Drill Team Photo 41 42</div> <div>30 of Danielle Smalley</div> <div>31 24 Calculation of 50 51</div> <div>32 Butane Expelled</div> <div>33 25 Curriculum Vita 66 66</div> <div>34 of Dr. Crutchfield</div>

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1 number, but you also had the phone number for the Koch
2 area representative?
3 A I'll agree that I had numbers to Koch that did
4 not work.
5 MR. BRENNAN: Your Honor, I would just
6 object to the nonresponsive portion of his answer.
7 THE COURT: Mr. Mayfield, did you hear
8 the question?
9 THE WITNESS: Yes. I had --
10 THE COURT: Okay. Listen to me. Did you
11 hear the question?
12 THE WITNESS: I think so. I'm not sure.
13 THE COURT: Do you want him to repeat it?
14 THE WITNESS: Please.
15 MR. BRENNAN: Your Honor, we'll just pass
16 the witness at this time.
17 THE COURT: Anything further?
18 MR. LYON: No.
19 THE COURT: Sir, you may step down.
20 Call your next witness.
21 MR. McCAULEY: Your Honor, at this point
22 we will present by videotape the deposition of
23 James Tucker. It'll take about 41 minutes.
24 THE COURT: Okay. Forty-one minutes.
25 You got 41 minutes in you? Do you want

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1 to take five minutes, or you want to take a 15-minute
2 break when we get through with 41 minutes?
3 No response. Go ahead.
4 Is that okay with y'all? Okay. Good.
5 You've just got to let me know. I'm always going to
6 take by your silence that we're going to move on.
7 MR. McCAULEY: The videotape deposition
8 of James Tucker, taken on March 11, 1999, a Koch
9 employee.
10 JAMES TUCKER,
11 having been duly sworn, testified as follows by
12 videotape deposition:
13 DIRECT EXAMINATION
14 BY MR. McCAULEY:
15 (Videotape playback begins.)
16 Q (by Mr. Wolf) Tell me your full name.
17 A James Tucker.
18 Q When did you first start working for Koch?
19 A 1980, I started contracting for them, and I
20 went to work for them full-time in 1981.
21 Q What was your job in the corrosion department?
22 A I was a corrosion technician.
23 Q What would you do as a corrosion technician?
24 A Read rectifiers, take care of rectifiers that
25 had problems. If an area rep called in with a problem

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1 with a rectifier, we'd go out and troubleshoot it.
2 Q What would you do on the Sterling I Pipeline?
3 A Well, we would -- you're talking about as an
4 operation technician?
5 Q Well, we'll start there.
6 Working at -- working under Ben Ennis, what
7 would you do as a -- what would you do, working for
8 Koch with regard to Sterling I?
9 A Well, I was -- at one time I relieved Don
10 Carson as an area rep.
11 Q How long was that relief job?
12 A Four or five, six months. Something like
13 that.
14 Q Four to six months?
15 A Something like that.
16 Q What year was that?
17 A Oh, --
18 Q About '95?
19 A Yes, sir.
20 Q Okay. Well, what was corrosion tech work?
21 What would you say that was in 1995?
22 A Well, it was an area I was relieving
23 Don Carson while he was on leave of absence, working on
24 the Sterling I Pipeline project.
25 Q I'm handing you what was -- what is marked as

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1 Deposition Exhibit No. 1 to your deposition.
2 That's a bimonthly rectifier report; correct?
3 A Yes, sir.
4 Q When was the last time you saw that?
5 A Saw this?
6 Q Yes, sir.
7 A Probably a week or so ago.
8 Q And before that, when was the last time you
9 saw it?
10 A I guess 9/13 of '95.
11 Q Okay.
12 A Maybe 9/20.
13 Q Do you see the signature up at the top of the
14 page, next to the word "signature"?
15 A Yes, sir.
16 Q Whose signature is that?
17 A That's mine.
18 Q Did you create this document?
19 A Yes, sir.
20 Q Did you enter the data that's included in this
21 document?
22 A Yes, sir.
23 (Videotape playback paused.)
24 MR. McCAULEY: Your Honor, at this time,
25 we'd offer, I believe, Plaintiff's Exhibit 26 --

Volume 5 Trial on Merits
October 7, 1999

Danny Smalley, et al, vs.
Koch Industries, Inc., et al

<p style="text-align: right;">Page 157</p> <p>1 Plaintiff's Exhibit No. 27, what was Exhibit 1 to 2 Mr. Tucker's deposition, which he's just identified as 3 the document he created and all writing thereon as 4 being his.</p> <p>5 MR. BRENNAN: No objection. 6 THE COURT: Admitted. 7 (Plaintiff's Exhibit No. 27 was 8 admitted.) 9 MR. McCAULEY: I'd like to publish this. 10 THE COURT: All right. 11 (Videotape playback resumed.) 12 Q (by Mr. Wolf) While you were filling in for 13 Don Carson in 1995, one of your duties was to -- was to 14 take bimonthly rectifier readings for the area that 15 Don Carson covered; correct?</p> <p>16 A Yes, sir.</p> <p>17 Q And that would include the Chico lateral and 18 Sterling I from Farmersville south to Corsicana; 19 correct? And that may be a little bit beyond 20 Corsicana; correct?</p> <p>21 A Yes, sir.</p> <p>22 Q All right. Were these readings correct at the 23 time you took them?</p> <p>24 A Yes, sir. This is the readings I wrote down. 25 That's the readings I read.</p>	<p style="text-align: right;">Page 159</p> <p>1 can't really tell by the way the copier did it. 2 Q And all of these readings were taken during 3 September of '95; correct?</p> <p>4 A Yes, sir.</p> <p>5 Q That was the month for the rectifier reading, 6 the odd month that Sterling I would have its rectifiers 7 read on; correct?</p> <p>8 A Yes, sir.</p> <p>9 Q I'm going to show you a map of Kaufman County. 10 Mr. Floyd has identified this as a map with a 11 representation of Sterling I that passes right through 12 the middle of Kaufman County.</p> <p>13 And along Sterling I are milepost markers. Do 14 you see those mile markers?</p> <p>15 A Uh-huh.</p> <p>16 Q They're the circles with the numbers inside 17 them, with the line pointing to what is the pipeline. 18 Okay?</p> <p>19 A Right.</p> <p>20 Q Now, Mr. Floyd has identified for us that the 21 rupture point is at where it says 8, and it has a 22 little quotation mark out next to it. Do you see where 23 it says 8-inch?</p> <p>24 A Uh-huh.</p> <p>25 Q All right. Now, if that's the rupture point,</p>
<p style="text-align: right;">Page 158</p> <p>1 Q Have you seen any other versions of that 2 document, which is Exhibit 1 to your deposition?</p> <p>3 A Yes, sir.</p> <p>4 Q All right. Talking only about Exhibit 1 to 5 your deposition, at the time you made that document, 6 you were making that in the ordinary course of your 7 business, working as an area rep, in that you were 8 required to go out and take bimonthly rectifier 9 readings; correct?</p> <p>10 A Yes, sir.</p> <p>11 Q And you had personal knowledge of the contents 12 of the document at the time you made it; is that 13 correct?</p> <p>14 A Yes, sir.</p> <p>15 Q All right. Look at M9. There's a date out to 16 the side of that; correct?</p> <p>17 A It appears to be a date.</p> <p>18 Q All right.</p> <p>19 A There's dates on the others --</p> <p>20 Q Okay.</p> <p>21 A -- that would lead you to believe -- it 22 says -- the one couple down says 9 -- looks like 9/22, 23 and the couple above looks like 9/13.</p> <p>24 Q And the one on M9 looks like 9/20/95; correct?</p> <p>25 A I don't know if it's 20 or 26 or what. I</p>	<p style="text-align: right;">Page 160</p> <p>1 looking at that map, can you tell us what would be the 2 closest rectifier to the rupture point?</p> <p>3 A It would appear to be 325.</p> <p>4 Q That would be rectifier M9?</p> <p>5 A That's what it appears to be, right there.</p> <p>6 Q Now, at the day that you read rectifier M9 in 7 September of 1995 and recorded that information on the 8 bimonthly rectifier report that you're required to keep 9 by law, what did you write for the status of that 10 rectifier?</p> <p>11 A I wrote "okay" from the left to right --</p> <p>12 Q No. I want to know about the status. What 13 was the status of the rectifier?</p> <p>14 A Down -- DC volts down.</p> <p>15 Q Okay.</p> <p>16 A Comments, lightning arrester -- or lightning 17 arrester --</p> <p>18 Q All right. You also had a note next to where 19 it said Kaufman, "call Alan Taylor."</p> <p>20 A Called, c-a-l-l-e-d, called Alan Taylor. He 21 was the corrosion control supervisor.</p> <p>22 Q During 1995?</p> <p>23 A Yes, sir.</p> <p>24 Q Okay. Did you call Mr. Taylor and tell him 25 that rectifier M9 was down?</p>

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1 A James Tucker.
 2 Q Is that your signature?
 3 A Yes, sir.
 4 Q Did you record the data included on that page
 5 of Exhibit 2, the July bimonthly rectifier reading?
 6 A Yes, sir.
 7 Q Did you do that in the ordinary course of your
 8 business?
 9 A Yes, sir.
 10 Q All right. And at the time you recorded that,
 11 you were taking those readings -- strike that.
 12 At the time you made those recordings, you
 13 were reading values that you were observing; correct?
 14 A Right.
 15 Q And you had personal knowledge of those, those
 16 readings at the time you were recording them on that
 17 document; correct?
 18 A At that time? Yes, sir.
 19 Q Right.
 20 So we use -- or Koch used 641 kilowatt hours
 21 between July bimonthly rectifier reading and the
 22 earlier May bimonthly rectifier reading; correct?
 23 A Yes, sir.
 24 Q All right. And to find out how much power was
 25 used between July and September, simply subtract 39535

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1 from the earlier reading of 39104; correct?
 2 A Uh-huh.
 3 Q And you should get -- should tell you that
 4 there were 431 hours -- kilowatt hours of power used
 5 for that time frame; is that correct?
 6 A Yes, sir.
 7 Q Now, the next bimonthly rectifier reading
 8 would be -- after September '95 would be what month?
 9 November '95; correct?
 10 A Uh-huh. Bimonthly.
 11 Q Now, if you would, please, direct your
 12 attention to the AC meter reading found for the M9
 13 rectifier.
 14 A Okay.
 15 Q If the AC meter reading found at M9
 16 November 1995 was 39539 and the value found in
 17 September of '95 was 39535, it would have used -- M9
 18 would have used four kilowatt hours; correct?
 19 A According to that right there, yes.
 20 Q Is there something wrong with that right
 21 there?
 22 A Appears to me that something's wrong.
 23 Q Wrong with the way I recorded it or wrong with
 24 the way that M9 was using power?
 25 A The amount it was using power.

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1 Q That's what was wrong with that; right?
 2 A That's what it appears.
 3 Q It appears -- and I've -- as a summary to your
 4 testimony, I've marked the -- as Exhibit 4, power usage
 5 of M9. And I've recorded that data that we've just
 6 discussed; correct?
 7 A Right.
 8 Q But we do know one thing. If it only used
 9 four kilowatt hours, the bottom line is most of that
 10 two-month period the M9 rectifier was off or not
 11 drawing any power.
 12 A It appears that it was off.
 13 Q Now, you were in Kaufman County in a period at
 14 least including July, September -- July, August, and
 15 September of 1995; right? That's when you were filling
 16 in for Don?
 17 A Right.
 18 Q It was during that time that you also helped
 19 fill in for Don during the construction or
 20 reconstruction, reconditioning of Sterling I; correct?
 21 A As an area rep.
 22 Q Is that correct?
 23 A Yes.
 24 Q Do you know what corrosion is?
 25 A Yep.

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1 Q All right. Have you ever seen corrosion on a
 2 pipeline, a metal pipeline?
 3 A Yes, sir.
 4 Q Have you ever seen corrosion on Sterling I?
 5 A Yes, sir.
 6 Q Do you know what tape coating is?
 7 A Yes, sir.
 8 Q Have you ever seen the tape coating on
 9 Sterling I?
 10 A Yes, sir.
 11 Q Do you know what disbonded coating means?
 12 A Yes, sir.
 13 Q All right. Is your -- my understanding of
 14 disbonded coating is coating that's not sticking well
 15 to the pipe like it's supposed to, not wrapped tight
 16 and good -- and adhering to the pipe.
 17 Is that what your understanding is?
 18 A Yes, sir.
 19 Q Okay. In 1995, did you ever see disbonded
 20 coating on Sterling I?
 21 A On the -- on the digs that I was present, and
 22 that's all I can speak for.
 23 Q I understand.
 24 A The digs that I was -- I walked up and was
 25 present.

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1 Q I just want to know to --
2 (Videotape playback paused.)
3 MR. BRENNAN: Your Honor, I would like to
4 insert an objection of optional completeness right
5 here. Plaintiffs failed to include one question and
6 one answer that is necessary to fully understand
7 Mr. Tucker's testimony on this subject.
8 THE COURT: Tell me what page and line
9 you want to include.
10 MR. BRENNAN: It's on page 68, line 21
11 through line 25.
12 MR. McCAULEY: He's certainly entitled in
13 cross-examination to address that, Your Honor.
14 THE COURT: No. I think optional
15 completeness is appropriate for page 68, lines 21
16 through -- I'm sorry -- lines 19 through 25. You can
17 read them.
18 MR. BRENNAN: Okay. Question asked by
19 Mr. Wolf: And that's all I'm asking about, is what you
20 have knowledge of.
21 Answer by Mr. Tucker: They were having
22 to scrape with machetes. I'm talking about scrape the
23 coating off to get to the pipe -- scrape the coating
24 off the pipe to get to the anomalies.
25 THE COURT: Okay. Go ahead.

1 A Well, I think it was a conference call.
2 Q I understand.
3 You were involved in that call, and David
4 Kilian was involved in that conversation.
5 A I think there was three or four of us
6 involved.
7 Q But at least the two people I named, you and
8 Mr. Kilian, and probably Don Carson?
9 A Right. There were several.
10 Q All right. And it concerned you enough that
11 you were finding this -- these anomalies, but they
12 weren't on your Vetco dig sheets where you were told to
13 go dig, that you decided to engage a conference call
14 with the people up in Medford, including David Kilian,
15 and tell them about it.
16 A Yes, sir.
17 Q You had talked to your boss.
18 A Right.
19 Q And you had told him about your conference
20 call that you had concerning not fixing some of the
21 anomalies that you were finding.
22 A I think our boss was involved in that meeting.
23 Q Oh, he was in that conversation?
24 A He was in there. There was a whole roomful.
25 Q Okay. I thought they were --

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1 (Videotape playback resumed.)
2 Q (by Mr. Wolf) -- if when you saw corrosion on
3 Sterling I, you ever saw perfectly adhered or, you
4 know, well-adhered coating over the corrosion that you
5 saw?
6 A No. It was usually -- there was -- there was
7 some damage to the -- to the coating.
8 Q Anytime you had that piece of pipe and the
9 outer wall had corroded through at 29 -- more than
10 29 percent, that's what y'all would have to fix; right?
11 A Well, that was -- that was within the, the
12 criteria.
13 Q Okay.
14 A And we -- you know, we, we seen some areas
15 that had, had corrosion that weren't on the sheet, per
16 se, and we called -- or Don called Medford. And we
17 quizzed them about it because, you know, to the
18 untrained eye, which, you know, we were untrained, as
19 far as what anomalies -- you know, we were told if it
20 was like 29 to 30 percent wall loss, that was anomalies
21 that we were removing.
22 Q Okay. In fact, you had a conversation with
23 David Kilian at one time; correct? About those --
24 seeing anomalies that weren't on the sheet and wanted
25 to know what to do about them.

1 A It was a conference call in the room.
2 Q I understand.
3 I thought they were two separate
4 conversations. So everybody was in on this conference
5 call.
6 A Right.
7 Q Some of y'all were down in Texas; some of
8 y'all were up in Medford.
9 A You know, I wasn't in Medford, so I don't know
10 who-all was in the room. But I'm thinking that Ben
11 Ennis was in there and David and probably Charles.
12 Q David Kilian and Charles Misak?
13 A Yeah. And possibly Alan Taylor.
14 Q Did you agree with the decision to leave the
15 anomalies you were finding that didn't meet the
16 criteria?
17 A I don't remember if I agreed or disagreed. I
18 think I kept my mouth shut and went on because after
19 talking to them and -- I mean, I'm not an expert, and
20 the engineers are trained. And they know what the pipe
21 will do after the hydrostat. And I wasn't in charge of
22 the -- of that part of the business. That was
23 Don Carson's.
24 I was there just to help Don to make sure all
25 the safety considerations were done, as far as hard

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1 Q And by the same reasoning and logic, we can
2 determine that between September '95 and November '95,
3 M9 was hardly working at all.
4 A Probably.
5 Q Is that right?
6 A Probably.
7 Q Same logic; right?
8 A Right.
9 Q What's good for the goose is good for the
10 gander; right?
11 A Right.
12 Q All right. What's good for '96 is good for
13 '95 on Sterling I; right?
14 A Yes.
15 Q Now, 3/18/96, M9 was no longer working;
16 correct?
17 It actually says in the bimonthly rectifier
18 reading, which the law requires an operator keep -- it
19 actually says not working; correct?
20 A Correct.
21 Q All right. That's March 18th, 1996, not
22 working.
23 Now, if you would go to the next page, which
24 will be the May 1996 bimonthly rectifier reading. Can
25 you tell me the status of the M9 rectifier at that

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1 time?
2 A Comments are "off."
3 Q It was off; correct?
4 A Yes.
5 Q And that's -- what's the date of that
6 bimonthly rectifier reading?
7 A May the 20th, '96.
8 Q All right. You know it was off because it
9 hadn't used any power, don't you?
10 A Says "off".
11 Q Now, the next rectifier report that we've been
12 provided by Koch was done by Jerry Selter, and I've
13 turned to the page for you. It was done on 7/1/96.
14 July 1st, '96, according to the document.
15 Can you find rectifier M9 on that sheet?
16 A Yes.
17 Q There's not a -- there's not even a meter
18 reading for that sheet, is there?
19 A No, sir.
20 Q In fact, there's just one thing in the
21 "Comment" section. What does it say?
22 A "Bad."
23 Q Now, there's not an August bimonthly rectifier
24 reading for the Sterling I Pipeline, is there, because
25 that's an even month; right? You just take them in

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1 July and then again in September; right?
2 A Every other month.
3 Q Exhibit No. 6 to your deposition is the power
4 usage that we've just gone through in your testimony of
5 M9 during 1996, -- correct? -- where I've put the AC
6 meter values, the dates those values were taken, and
7 then also the comments; correct?
8 A I just read what was on the material.
9 Q And that's what I've reflected in Exhibit 6 to
10 your deposition; correct?
11 A Yep.
12 Q This number right here under AC meter,
13 number -- rectifier M9 AC meter, is that the number
14 where you weren't sure if that's a three or an eight?
15 A Right.
16 Q Can you hold that up so the camera can zoom in
17 on it?
18 A 5 -- 5 or a 6 is what we discussed.
19 Q Okay. Okay. Can you hold the camera up --
20 hold that up so the camera can zoom in on that, and
21 I'll point.
22 A (Witness complies.)
23 Q And you don't know whether that says 639 or
24 539; correct?
25 A Correct.

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1 Q Koch gives you these Franklin Planners to help
2 you as -- sort -- as a business tool, keep your time,
3 keep your activities recorded; correct?
4 A Yes, sir.
5 Q Here's August 8, '95. What does it say you
6 were doing at seven o'clock that day?
7 A It says going to Kaufman, check test site.
8 Q What would you be checking at the test site?
9 A Test site. Test site. Possibly the -- maybe
10 a pressure test on some pipe or something.
11 Q Exhibit 1 and Exhibit 5, which is generally
12 the same document with a little bit different
13 information -- that's the September 13, 1995 bimonthly
14 rectifier readings; correct?
15 A Correct.
16 Q And I was looking at your calendar entry from
17 September 13, 1995. And I notice that there was some
18 mention of doing rectifier readings on here; for
19 example, ten a.m., Denton rectifier reading. Do you
20 see that?
21 A Uh-huh.
22 Q You would have been in Denton, reading the
23 Chico --
24 (Videotape playback paused.)
25 MR. BRENNAN: Your Honor, I'm just going

33

<p style="text-align: center;">REPORTER'S RECORD</p> <p style="text-align: center;">VOLUME 8 OF 24 VOLUMES</p> <p style="text-align: center;">TRIAL COURT CAUSE NO. 51458</p> <p>DANNY SMALLEY, INDIVIDUALLY) IN THE DISTRICT COURT AND AS INDEPENDENT) ADMINISTRATOR OF DANIELLE) DAWN SMALLEY, DECEASED))) VS.) KAUFMAN COUNTY, TEXAS)) KOCH INDUSTRIES, INC., KOCH) PIPELINE COMPANY, L.P.,) KOCH HYDROCARBON COMPANY,) KPL/GP, INC., AND RONALD) GANT) 86TH JUDICIAL DISTRICT</p> <p style="text-align: center;">TRIAL ON MERITS</p> <p>On the 12th day of October, 1999, the following proceedings came on to be heard in the above-entitled And numbered cause before the Honorable Glen M. Ashworth, Judge presiding, held in Kaufman, Kaufman County, Texas:</p> <p style="text-align: center;">Proceedings reported by machine shorthand.</p>	<p style="text-align: right;">Page 3</p> <p style="text-align: center;">WITNESS INDEX</p> <p style="text-align: center;">Voir Direct Cross Redirect Recross Dire</p> <p>3 ROGER 4 FLOYD 5 45</p> <p>5 DON 6 CARSON 61 78 82 111 144 167 178</p> <p>7 CHARLES 8 POWELL 182 243 245 245 9 247</p> <p style="text-align: center;">ALPHABETICAL WITNESS INDEX</p> <p style="text-align: center;">Voir Direct Cross Redirect Recross Dire</p> <p>13 DON 13 CARSON 61 78 82 14 111 144 167 178</p> <p>15 ROGER 16 FLOYD 5 45</p> <p>17 CHARLES 17 POWELL 182 243 245 245 18 247</p> <p style="text-align: center;">EXHIBIT INDEX</p> <p style="text-align: center;">PLAINTIFF'S DESCRIPTION OFFERED ADMITTED</p> <p>21 NO. 48 Intercompany 11 11 22 Koch Memo</p> <p>23 49 Intercompany 26 26 24 Koch Memo</p> <p>25 50 Carlson's Roles, 66 67 Responsibilities</p>
<p style="text-align: right;">Page 2</p> <p style="text-align: center;">APPEARANCES</p> <p>3 Mr. Ted B. Lyon SBOT NO. 12741500 4 Mr. Marquette Wolf SBOT NO. 00797685 5 TED B. LYON & ASSOCIATES Town East Tower - Suite 525 6 18601 LBJ Freeway Mesquite, Texas 75150 7 Phone: (972)279-6571 ATTORNEYS FOR PLAINTIFF</p> <p style="text-align: center;">-AND-</p> <p>9 Mr. R. Michael McCauley 10 SBOT NO. 13383500 McCAULEY, MACDONALD, DEVIN & HUDDLESTON 11 3800 Renaissance Tower Dallas, Texas 75270-2014 12 Phone: (214)744-3300 ATTORNEY FOR PLAINTIFF</p> <p style="text-align: center;">-AND-</p> <p>14 Mr. Michael C. Steindorf 15 SBOT NO. 19134800 Mr. Richard S. Krumholz 16 SBOT NO. 00784425 Mr. Sean P. Brennan 17 SBOT NO. 00787135 FULBRIGHT & JAWORSKI 18 2200 Ross Avenue, Suite 2800 Dallas, Texas 75201 19 Phone: (214)855-8022 ATTORNEYS FOR DEFENDANTS</p>	<p style="text-align: right;">Page 4</p> <p>1 51 Pipeline Revision 81 82 Report</p> <p>2 52 Pipeline Revision 81 84 3 Report</p> <p>4 53 South Survey 86 86</p> <p>5 54 Bimonthly Rectifier 112 112 6 Report</p> <p>7 55 Bimonthly Rectifier 141 141 8 Report</p> <p>9 56 Bimonthly Rectifier 141 141 10 Report</p> <p>11 57 Bimonthly Rectifier 141 141 12 Report</p> <p>13 59 Bimonthly Rectifier 141 141 14 Report</p> <p>15 60 Monthly Power Usage 144 144</p> <p>16 61 Curriculum Vitae 187 187 of Powell</p> <p>17 62 Unknown 237</p> <p>18 63 Vetco Presentation 251 251</p> <p>19 64 Round Chart 251 252</p> <p style="text-align: center;">EXHIBIT INDEX</p> <p style="text-align: center;">DEFENDANTS' DESCRIPTION OFFERED ADMITTED</p> <p>21 NO. 23 Affidavit of 59 60 22 Rhodes</p> <p>23 24 Pipeline Revision 147 147 24 Report</p> <p>25 25 Pipeline Revision 148 149 26 Report</p>

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1 try it any quicker to cut corners, but we're going to
2 try it as quickly as we can to be mindful of your time
3 and the rights of the parties, but nonetheless, just so
4 you know, we are a little ahead of schedule.
5 We're sure not behind schedule which is
6 the most important.
7 Go ahead.
8 DON DAVID CARSON,
9 having been first duly sworn, testified as follows:
10 DIRECT EXAMINATION
11 BY MR. WOLF:
12 Q Mr. Carson, could you tell the jury your name?
13 A Don David Carson.
14 Q You work for Koch; is that correct?
15 A Yes, sir.
16 Q Your office -- or you work out of a little town
17 near Corsicana; is that correct?
18 A Yes, sir.
19 Q The Sterling I pipeline that we're here about
20 today, there's a piece of it there in front of you.
21 That passes through Corsicana, and there's a pump
22 station there; correct?
23 A Yes, sir.
24 Q That's about 46 miles south of here; right?
25 A I believe so.

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1 Q Who do you actually work for? What's the name
2 of the company you actually work for?
3 A Koch Pipelines, L.P.
4 Q All right. How long have you worked for Koch
5 Pipeline, L.P.?
6 A I believe they changed from Koch Hydrocarbon
7 in 1995 maybe. I'm not sure.
8 Q And the --
9 THE COURT: Can you hear Mr. Carson?
10 Mr. Carson, the jury has indicated you
11 need to speak up a little bit. Might be helpful if you
12 direct your responses in the direction of the jury, so
13 your voice will carry that, that way.
14 THE WITNESS: Yes, sir.
15 Q (by Mr. Wolf) Mr. Carson, the focus of my
16 questions today will be for the 1995 and 1996 time
17 frame unless I ask you otherwise. Okay?
18 During that time frame, your supervisor was a
19 man named Charles Misak; is that correct?
20 A Yes, sir.
21 Q He worked for Koch Hydrocarbon Company during
22 that time; correct?
23 A Yes, sir.
24 Q And who, who was his supervisor?
25 A David Kilian.

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1 Q Okay. And who did Mr. Kilian work for?
2 A Jim Elmore.
3 Q Okay. Mr. Kilian, Mr. Misak, and Mr. Carson,
4 yourself, during that period of time, '95 to '96, all
5 of you working for different companies from time to
6 time; correct? All under the Koch Industries, Inc,
7 umbrella; correct?
8 A Yes, sir.
9 Q And all of you during that period of time --
10 as far as your work with this Sterling I pipeline, you
11 were subject to the direct control of the company
12 called Koch Industries, Incorporated; correct?
13 A Yes, sir.
14 Q That remains the same today; correct?
15 A Yes, sir.
16 Q Is there any difference in your mind, whether
17 it matters or not, what company you're working for at
18 any given time?
19 MR. KRUMHOLZ: Objection. Calls for
20 speculation and a legal conclusion as to what effect it
21 might have working for different companies.
22 THE COURT: Overruled.
23 A No, it doesn't.
24 Q (by Mr. Wolf) It's just -- these company
25 names are just a way to divide up things, a tool for

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1 them to organize their business, -- correct? -- as far
2 as you know?
3 A I guess so.
4 Q It doesn't really make a difference to you,
5 one way or the other; right?
6 A No.
7 Q If someone from Koch Industries tells you to
8 do something, you'll do it; correct?
9 A Yes, sir.
10 Q If someone from Koch Pipeline Company, LP
11 tells you to do it, you'll do it; correct?
12 A Yes.
13 Q If someone from Koch Hydrocarbon Company -- if
14 they tell you to do something, you'll do it; correct?
15 A Yes, sir.
16 Q And the same can be said, as far as all three
17 companies for anything dealing with Sterling I;
18 correct?
19 A Yes, sir.
20 Q As far as you know, all three companies have
21 -- share control of that pipeline; correct?
22 A As far as I know. Yes, sir.
23 Q But outside of Koch, away from underneath the
24 Koch umbrella, during '95 and '96, there was no one
25 else in charge or responsible for that Sterling I

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1 A A corrosion hole.
2 Q How big?
3 A I don't remember.
4 Q They do a leak report when they have a leak
5 after a hydrostatic test; correct?
6 A Yes, sir.
7 Q And the place that you found that leak was at
8 milepost 315; correct? Post Oak Bend area?
9 A Highway 987?
10 Q Highway 987.
11 A Yes, sir.
12 Q Here's Plaintiff's Exhibit No. 32. Here's
13 that leak report from early -- it's April 4 -- I'm
14 sorry, April 9, 1995; correct?
15 A Yes, sir.
16 Q At the Post Oak Bend area; right?
17 A Yes, sir.
18 Q What did they find? They found a rupture
19 caused by external corrosion; correct?
20 A Yes, sir.
21 Q And it was split 13 inches in length; correct?
22 A I don't remember that.
23 Q You don't remember that, but that's what the
24 report says?
25 A Yes, sir.

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1 Q How long is this split? About 13 inches?
2 A Yes, sir.
3 Q Caused by external corrosion?
4 A Yes, sir.
5 Q All right. Then in July, they did another
6 hydrostatic test, and Koch accepted that test?
7 A Yes, sir.
8 Q Okay. But then after they accepted that test,
9 you were out doing a lot more repairs; right? Your
10 repairs weren't done, were they?
11 A Yes, sir. That's correct.
12 Q That's correct.
13 You were going -- still going, going all the
14 way through Kaufman County, still had some in Kaufman
15 down through Henderson and Navarro County to Corsicana,
16 that 46 miles in particular; correct?
17 A Yes, sir.
18 Q And you found, after July 18th, corrosion on
19 as much as 85 percent through the wall; right?
20 A Yes, sir.
21 Q Getting down to paper thin between the product
22 in the pipeline and the outside environment; correct?
23 A Paper thin?
24 Q Thirty-thousandths of an inch.
25 Twenty-eight-thousandths of an inch, actually.

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1 Thin paper, isn't it? Is that a "yes"?
2 A It's not paper.
3 Q Right. It's corroded steel.
4 A Yes, sir.
5 Q That's what it is; correct?
6 A Yes, sir.
7 Q Okay. Now, every time you did a dig in 1995
8 and found your corrosion, you also found at that very
9 spot disbonded coating; right?
10 A Yes, sir.
11 Q You know what I mean by "disbonded coating"?
12 A It had little slits and wrinkles, bubbles.
13 Q Can you see the screen?
14 A Yes, sir.
15 Q Are we looking at disbonded coating?
16 A Yes, sir.
17 Q You're seeing stuff like that -- you saw stuff
18 like that in 1995; right?
19 A Got a lot of dirt on there. We cleaned it
20 off.
21 Q Before you cleaned it off. Of course, it's
22 got dirt on it, it's buried in dirt; right?
23 A Yes.
24 Q I think everybody understands that, but what
25 you see is disbonded coating; correct? You see here?

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1 A Wrinkle.
2 Q Here, here, here. This is disbonded coating;
3 correct?
4 A Crinkles. Yes, sir.
5 Q That's disbonded; right?
6 A (Witness nods head up and down.)
7 Q And that's what you saw in 1995. Every time
8 you dug up, you found corrosion, you saw disbonded
9 coating, not dissimilar from this; right?
10 A Not every time.
11 Q Not every time.
12 But every time you did, you noted it in
13 your -- in your 4-in-1 reports; correct?
14 A Yes, sir.
15 Q Sometimes you'd note it as fair; sometimes
16 you'd note it as poor; correct?
17 A Sometimes good.
18 Q For example, here in a place on 8/22/1995, you
19 found pit depths nearly halfway through the wall, fair,
20 fair coating; correct?
21 A Yes, sir.
22 Q Disbonded, nevertheless; right? That's
23 disbonded coating you're talking about.
24 A Some locations, yes.
25 Q Well, Mr. Carson, you know enough about

34

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1 Alan, at, at one time when we'd made some changes, had
2 the electrical and the mechanic or -- and the corrosion
3 groups.
4 Q Uh-huh.
5 A And then we split that, and then Alan took
6 over the corrosion group totally.
7 Q Okay. Were you part of the decision to put
8 Alan Taylor in?
9 A Yes, I was.
10 Q What was -- did Alan Taylor have any corrosion
11 engineering experience at that time?
12 A When he initially took over --
13 Q Yes, sir.
14 A -- the group?
15 Not to my knowledge.
16 Q Did Alan Taylor at that time have the ability
17 to supervise corrosion technicians?
18 A He had the capability to supervise
19 technicians, yes.
20 Q All right. Did he have the capability to
21 evaluate and design cathodic protection systems and
22 programs?
23 A Probably not at that time.
24 Q Did he have to ability to implement and
25 monitor education and training of corrosion personnel?

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1 A He, himself, educate?
2 Q Yeah.
3 A Probably, probably not.
4 Q All right. And, and you knew that, --
5 A Yes, sir.
6 Q -- even though y'all were going to put him in
7 as the corrosion supervisor?
8 A Uh-huh.
9 Q 1993 -- is that the time frame when
10 market-based management was being implemented in
11 Medford?
12 A Yeah. To the best of my recollection, it was
13 in that time frame.
14 Q Okay. That's the same time frame when you and
15 the other supervisors at Medford had decided Cary
16 Fredrick should be replaced by Alan Taylor; correct? As
17 the corrosion supervisor.
18 A That's when we put Cary or when we put Alan
19 Taylor over the corrosion group, yes.
20 Q All right.
21 A In that time frame.
22 Q All right.
23 (Vidotape playback paused.)
24 MR. McCAULEY: That concludes the
25 selected portions of that deposition, Your Honor.

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1 MR. KRUMHOLZ: Your Honor, we're not
2 going to play any portions of the videotape of Mr.
3 Dayton because we're going to call him in our case in
4 chief.
5 THE COURT: Okay. Call your next
6 witness.
7 MR. LYON: Your Honor, David Kilian by
8 video.
9 MR. McCAULEY: Your Honor, this is going
10 to be a fairly long video.
11 MR. LYON: It's 122 minutes.
12 THE COURT: It's how long?
13 MR. McCAULEY: 122 minutes.
14 THE COURT: Okay. Well, we've got an
15 hour. Is there a --
16 MR. LYON: We can break.
17 THE COURT: I mean, is there a break
18 point in there?
19 MR. McCAULEY: It's a -- there's a --
20 there's a point we can break in the presentation.
21 THE COURT: Anytime after 4:30, if, if
22 there's a cogent breaking point, that will be fine.
23 (Pause.)
24 MR. McCAULEY: I'll try to pick a
25 reasonable point and stop --

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1 THE COURT: Okay.
2 MR. McCAULEY: -- soon after 4:30.
3 THE COURT: Just kind of follow along
4 until we get to some cogent point. That will be fine.
5 THE REPORTER: Raise your right hand,
6 please.
7 (Witness sworn.)
8 DAVID LEE KILIAN,
9 having been previously duly sworn, testified as follows
10 by videotape:
11 DIRECT EXAMINATION
12 BY MR. WOLF:
13 Q Mr. Kilian, would you please state your full
14 name?
15 A My name is David Lee Kilian.
16 Q Tell me what corrosion prevention means to
17 you. Before we get into a whole bunch of questions
18 about corrosion, I want to make sure we're talking
19 about the same thing.
20 A Can you be more specific?
21 Q Well, is -- let me ask it this way. Is
22 corrosion prevention or corrosion control the same
23 thing as protecting a -- just -- with regard to a
24 pipeline, the same thing as protecting that pipeline
25 from corrosion by means of either coating or cathodic

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1 A No.

2 Q Okay. Now, you're not an engineer.

3 So on what basis did you make the statement,

4 by all good engineering practices? What do you know

5 about all good engineering practices?

6 A I had -- there was -- we have engineers at

7 Medford and else- -- elsewhere in the company that,

8 that provide that type of information.

9 Q So did some engineer ever provide you with

10 some information upon which you relied and which you

11 can tell us about, so that we know that -- how it

12 really happened, regarding the safety of operating that

13 pipeline after February of 1995?

14 A So was there an engineer that said that? Is

15 that the question?

16 Q Do you have anything you can demonstrate, that

17 would show where some engineer told you that, either in

18 writing --

19 Do you have a memo that shows it after an oral

20 conversation? I don't care what it is. Do you have

21 some record?

22 A I don't recall a memo.

23 Q Somebody told you, though?

24 A Yeah. There was engi- -- engineering

25 information available that said, such as the, the

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1 repair -- all the repair -- the, the repairs that were

2 made.

3 I mean, we -- I had engineers that, that

4 hydroed the line and smart-pigged the line, made the

5 repairs to the line, and then rehydroed the line.

6 Q And then reported to you some level of safety;

7 is that right?

8 A Yes.

9 Q Then who was that?

10 A The engineer that was over the project, Craig

11 Reed.

12 Q As the manager of operations for that,

13 including that area of operation of putting that

14 pipeline back into service, were you concerned that it

15 be safe for the public before it was put back into

16 service?

17 A Absolutely.

18 Q Well, you know that two people died as a

19 result of this leak, don't you? Are you aware of that?

20 A Yes.

21 Q What did you do, as the manager of operations

22 at Medford, to ensure yourself and satisfy yourself

23 that it was safe to reutilize that pipeline after

24 February of 1995?

25 MR. KRUMHOLZ: Objection, form.

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1 A We, we hydroed it. We smart-pigged it, and we

2 rehydroed it. We made all the repairs to, to -- the

3 repairs were made that were identified from the smart

4 pig report to a 30 percent criteria, leaving a 70

5 percent of the wall thickness of the pipe.

6 Utilizing good engineering standards, my

7 people utilized B31G to -- which is an industry

8 standard in relationship with pressure and, and wall

9 thickness.

10 If you think about what -- that's, that's,

11 that's the way that it's communicated in the CFR 42,

12 Part 195; that -- of what you need to do when you make

13 repairs.

14 After we made those repairs, as I mentioned,

15 we went back and, and hydroed -- rehydroed them to be

16 confident that the line was safe for operation.

17 Q (by Mr. McCauley) And you've just made a nice

18 description for me of what was done.

19 Now, I'll ask you the question one more time.

20 I know all that was done.

21 I'm asking you: What did you do, as the

22 director of operations for the pipeline that ultimately

23 killed these two children, to satisfy yourself in the

24 period right after February 1995 that that pipeline was

25 safe to operate? Did you do anything yourself as a

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1 manager to obtain information specifically which caused

2 you to reach that conclusion?

3 MR. KRUMHOLZ: Objection. Form.

4 A Yes.

5 Q (by Mr. McCauley) What?

6 A What I just described.

7 Q When did you first learn that there was a tape

8 or a coating disbonding problem on Sterling I?

9 A I don't recall when I first heard that.

10 Q Just give me the closest time frame you can

11 pin it down to.

12 A When they were making their repairs in '95, I

13 knew that they, they had found on a couple of them --

14 well, I don't know how many digs. I knew that they had

15 seen some disbondment.

16 Q When did you first learn that Roger Floyd was

17 considering replacing the pipeline or rewrapping or

18 recoating the pipeline, Sterling I?

19 A We'd discussed it off and on for several

20 months on what the best approach is.

21 Q As you've -- as you reflected back on the

22 events that led up to the leak and explosion and death

23 of these two kids, did you look back to see what the

24 results of those '95 digs were, in terms of any

25 disbonding problems?

35

PENGAD-Bayonne, N. J.
 DEPOSITION
 EXHIBIT
 27
 Carlson 12-2-97

MAIL TO MEDFORD-DO NOT FAX

DATE: 9-13-95
Day/Month/Year

SIGNATURE Samuel Tucker

Rect. No.	Mile Post	Location	A/C Meter	DC Volts	DC MIVolts	Comments
C-1		DECATUR	18030	5.8	13.6	9-13-95, Chuo Smide
C-2	45	DENTON	4490	9.9	12.3	9-13-95
C-2.5	60	TRAP 4 TO 8	05150	19.7	11.7	380400 north to 11.7
C-3		McKINNEY	off	off	off	HWY 2933 9-15-95
M-8	242.2	NORTH OF BELLS	11526	16.2	15.0	Chap Rd. 1897 9-15
S-9		FARMERSVILLE JUNCTN.	49614	5.03	23.3	
BOND	263	HIGHWAY 78A & 815 St	XXXX	XXXX	+2.6	
BOND	73.02	WEST McKINNEY	XXXX	XXXX	+5.8	west of jail Hwy 75 Knpth
BOND		MITCHELL ENERGY	XXXX	XXXX	Down	U.C.R. 1216 10-1-95
BOND		STERLING 1, FMRSVILLE	XXXX	XXXX		Chuo jet 9-13-95
BOND		CHICO, FARMERSVILLE	XXXX	XXXX		Chuo jet 9-13-95
M-7	290.4	NEVADA STATION	10688	11.9	16.1	NEW Brand Cables 9-
M-8	304	HIGHWAY 205 Air Port	13060	13.1	11.8	9-20-95
M-9	325	KAUFMAN (off w/ down)	39535	Down	Down	Lighting: Overwater 9-20-95
M-9.5	338	HIGHWAY 85	36239	17.9	20.9	9-20-95 9016 H det
M-10	360.7	CORSICANA STATION	off	64	64	off - DOWN 9-20-95
M-11	363	NAVARRO	0548	15.3	20.2	walk to Rectifier
M-12	364	BRITHOP NORTH	30412	15.9	55.6	5000 in field
M-13	366.5	BRITHOP	✓	✓	✓	Under water
M-14	368.8	STREETMAN	59417	9.5	24.0	Three Cattle Pen
M-16	373	STREETMAN	57763	15.3	6.7	
M-17	375	STREETMAN/KIRVIN	5916	6.3	24.3	Need Core Lead 11/1/95
M-18	380	NORTH KIRVIN	46321	15.4	9.3	Post on Road
M-19	383	SOUTH SHANKS 381	8334	Down	Down	Main Fuse Box Down + B
M-20	384	PRAZELS	02226	✓	✓	Lighting Sequence Down
M-21	384.7	KIRVIN/TEAGUE	06577	15.9	13.1	
M-22	385	SIMSBOROUGH	4920	8.2	9.8	? -
M-9-75		ROANE HWY 1129	16753	13.1	11.2	
S-11		QUINLAN STATION				
S-13		HIGHWAY 317 (ATHENS)	00853	3.6	2.4	
		Corsicana to mobil				GATE Locked

Coruscant le mobil

GATE Locked

WALK to North Pine Bay
M. 9. 75 HWY 1129 16753 Page
ECR 0120

Page 1

DC 0000364

DEPOSITION
EXHIBIT

36

KM Medford Division Koch (Cont.)

4.010 - 4.570

01/01/94 through 07/30/96



DC DC Grnd Bed Tap Struc Num
 O Date OVolts O Amps O Resist O KWH Off O Set O P/S O Fail O Remarks

Rect ID: K-09 NP: 4.090 Loc: N-S ROAD

Date	Volts	Amps	Resist	KWH	Off	Set	P/S	Fail	Remarks
01/01/94									SURVEY
01/15/94	15.70	19.59	0.80	33898					DON CARSON
03/17/94	19.80	17.20	1.15	34442					DON CARSON
05/20/94	15.60	19.25	0.81	35157					DON CARSON
07/27/94	15.70	15.10	1.04	35991					DON CARSON
09/30/94	15.90	11.89	1.33	36573					DON CARSON
11/11/94	15.90	10.79	1.47	36887					DON CARSON
01/24/95	16.20	9.03	1.79	37314					DON CARSON
03/29/95	22.10	10.72	2.06	37754					DON CARSON
05/29/95	24.90	9.95	2.50	38463					DON CARSON
07/27/95	24.99	8.90	2.80	39104					JAMES TUCK
09/13/95	25.00	9.00	2.77	39535					JAMES TUCK
11/15/95	23.80	26.53	0.89	39539					DON CARSON
01/01/96									SURVEY
01/01/96									SURVEY
01/29/96	24.90	8.99	2.77	40126					DON CARSON
03/29/96				40774					NOT WORKIN
05/20/96									NOT WORKIN
07/19/96									NOT WORKIN

UPSTREAM OF RELEASE

Replaced in 9/96

Rect ID: K-09.5 NP: 4.095 Loc: North South Dirt Road

Date	Volts	Amps	Resist	KWH	Off	Set	P/S	Fail	Remarks
01/01/94									SURVEY
01/15/94	18.50	19.65	0.94	17371					DON CARSON
03/17/94	18.40	17.44	1.05	18034					DON CARSON
05/20/94	18.20	21.42	0.85	18899					DON CARSON
07/27/94	17.90	22.75	0.78	20095					DON CARSON
09/30/94	18.30	21.27	0.86	21104					DON CARSON
11/11/94	18.20	21.52	0.84	21701					DON CARSON
01/24/95	18.40	20.64	0.89	22585					DON CARSON
03/29/95	18.50	20.13	0.91	23352					DON CARSON
05/29/95	18.30	21.95	0.83	24346					DON CARSON
07/27/95	17.74	22.10	0.80	25469					JAMES TUCK
09/13/95	17.90	20.90	0.85	26238					JAMES TUCK
11/15/95	17.90	19.25	0.93	26889					BRAD AVANT
01/01/96									SURVEY
01/01/96									SURVEY
01/29/96	18.10	16.40	1.10	27782					DON CARSON
03/29/96	18.60	16.42	1.13	28402					DON CARSON
05/20/96	18.50	16.07	1.15	29002					DON CARSON
07/19/96	18.60	16.60	1.12	29804					DON CARSON

- DOWN STREAM OF RELEASE

Rect ID: K-09.75 NP: 4.098 Loc:

Date	Volts	Amps	Resist	KWH	Off	Set	P/S	Fail	Remarks
01/24/95	13.30	11.01	1.20	15849					DON CARSON
03/29/95	13.60	10.89	1.25	16256					DON CARSON
05/29/95	12.30	24.80	0.49	6169					DON CARSON
07/27/95	13.50	11.00	1.22	16580					JAMES TUCK
09/13/95	13.10	11.20	1.17	16752					JAMES TUCK
11/15/95	13.00	11.16	1.16	17188					DON CARSON

PSM 004231

000004

09/06/96 Page 5

KP/B 011213

37

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1 musical chairs. I'll try to start now.
2 CHARLES MISAK,
3 having been previously duly sworn, testified as
4 follows, by videotape deposition:
5 DIRECT EXAMINATION
6 BY MR. WOLF:
7 Q Now, back in 1990 you were with Koch;
8 correct?
9 A Yes, sir.
10 Q And where were you working in 1990?
11 A I would have been working in the maintenance
12 department, the pipeline maintenance, or possibly with
13 pipeline construction.
14 Q Okay. Where?
15 A Out of Medford.
16 Q And what pipelines would you do maintenance
17 and construction on?
18 A Those for the Medford Division.
19 Q That would include the Sterling I Pipeline;
20 correct?
21 A If, if there was something that needed to be
22 done, yes.
23 Q In 1990 it wasn't called the Sterling I
24 Pipeline, though. It was called the Sterling Line;
25 correct?

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1 Okay. Were you ever made aware of the fact
2 that Sterling -- you -- that Sterling I, the pipeline
3 that exploded on August 24th, 1996 --
4 Back in, in 1991, were you ever made aware of
5 the fact that the people in corrosion and your
6 supervisors knew that Sterling I would have greater or
7 increased current requirements for the cathodic
8 protection system south of the Red River?
9 A No, I was not.
10 Q In 1995 you would have been expecting -- you
11 would have expected to have been made aware of that;
12 correct?
13 A Coming more to that time. Yes, sir.
14 Q Okay. Now, this -- I've just showed you this
15 memo and the 1990 memo concerning the digs. And you
16 would agree with me, wouldn't you, that they have some
17 historical data about the Sterling I Pipeline south of
18 the Red River, wouldn't you?
19 A Yes.
20 Q Were you ever made aware of this historical
21 data concerning Sterling I when you became the
22 supervisor who would -- someone who in 1995 would
23 expect to know about these types of issues?
24 A No, sir.
25 Q Is coating a cathodic issue, or is that a

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1 pipeline construction issue?
2 A Once it's in the ground, it is part of the --
3 part of the cathodic issue.
4 Q It's also a maintenance issue, isn't it?
5 A It -- the purpose of the coating is for the
6 cathodic protection or the protection of the pipeline.
7 Q Does Koch have to maintain that coating, or do
8 they just put it on their coating -- put it on their
9 pipelines and let it go?
10 A It -- you put it on your pipelines to protect
11 it. If -- then, in the event that it fails, then,
12 that's -- you -- that's why you have cathodic
13 protection.
14 Q Okay. So they don't have to maintain the
15 coating. They can just put it on there, and it's --
16 anytime there's a problem with it, you just let
17 cathodic protection fill in; right?
18 A You, you still have to maintain it if --
19 Q Okay.
20 A -- if that's the thing that needs to be done.
21 Q You have to maintain the coating.
22 A If that --
23 (Videotape playback paused.)
24 MR. KRUMHOLZ: Your Honor, for -- excuse--
25 me. For optional completeness purposes, just the four

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1 lines that were skipped there, --
2 THE COURT: All right.
3 MR. KRUMHOLZ: -- starting at line 12.
4 Q (read by Mr. Krumholz) So you have to
5 maintain the coating?
6 A Answer: You have to maintain the integrity of
7 the pipeline.
8 MR. KRUMHOLZ: End of optional
9 completeness.
10 (Videotape playback resumed.)
11 A If that's what's needed to do to maintain the
12 integrity of the pipeline, yes.
13 Q (by Mr. Wolf) What would make someone at Koch
14 today decide that, well, they need to maintain -- do
15 something to fix the coating, do some maintenance on
16 the coating?
17 A You would have -- you would have coating
18 deter- -- deterioration. It would be what -- it would
19 be determined by those knowledgeable in the subject;
20 that if we -- that repairing the coating is the most
21 economical and the best thing for the pipeline.
22 It would be a decision based on the -- on the
23 facts.
24 Q Okay. But what would -- what would ever get
25 the wheels in motion to make the decision?

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1 A From the -- from the '96 annual survey;
2 identified an area where a new ground bed needed to be.
3 Q Because the cathodic protection wasn't
4 adequate at the time?
5 A Because -- yes. The potentials were down.
6 Q Okay. But then the potentials were down. So
7 you knew -- Koch knew they needed a new ground bed, and
8 they were going to call it M8.5. And they got that in
9 the works; right?
10 A Yes.
11 Q But in the interim, before they got it
12 installed, M9 did fail.
13 A Yes.
14 Q Did that tell the people that you worked with
15 at Koch and yourself that, hey, we're going to have a
16 cathodic protection problem in Kaufman County? We
17 don't have good cathodic protection?
18 A I guess it, it says that there's a need for
19 work on the cathodic protection in that area.
20 Q Okay. So they knew they needed to work on it.
21 But it tell them -- did it tell them that it was
22 inadequate?
23 A No, it did not tell them that it was
24 inadequate.
25 Q Okay. Was anyone concerned that they had

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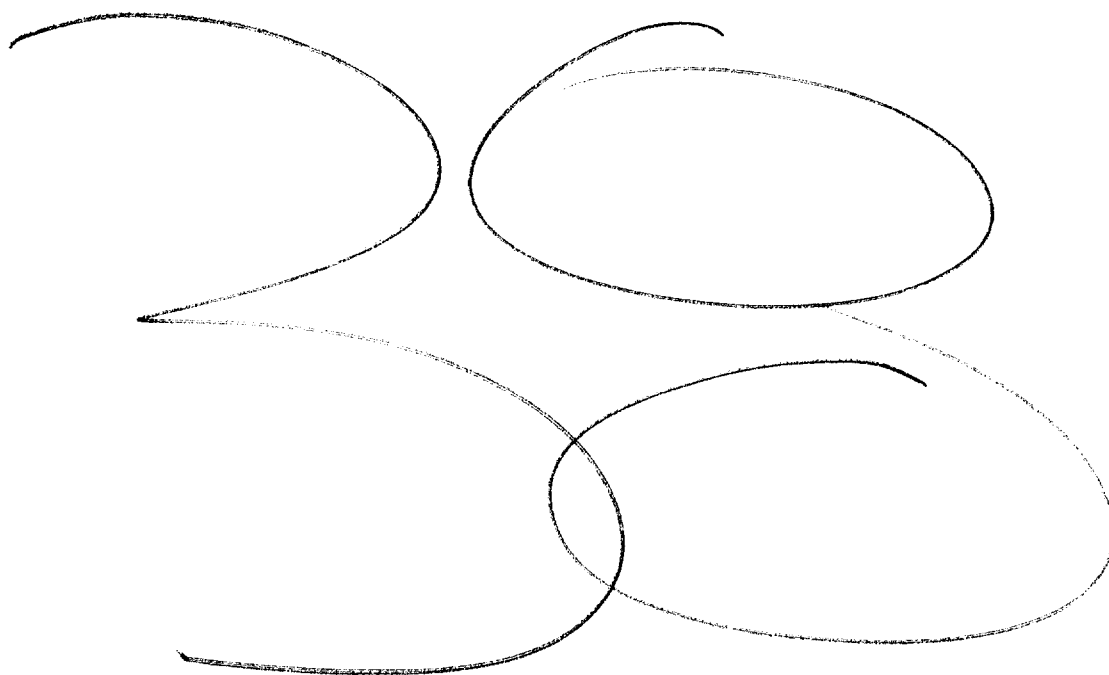
1 inadequate -- to your knowledge, was anyone concerned
2 that had they had inadequate cathodic protection in
3 that area between M8 and M9 and on downstream of M
4 after M9 failed?
5 A Yes.
6 Q Who was concerned?
7 A Jerry Selters and Alan Taylor.
8 Q Anybody else?
9 A And I was also.
10 Q If -- you knew M9 failed in March; right?
11 A Yes.
12 Q And you knew --
13 (Videotape playback paused.)
14 MR. McCAULEY: That concludes our reading
15 of that deposition, Your Honor.
16 MR. KRUMHOLZ: Your Honor, we have 15
17 minutes and 30 seconds, according to the videotape.
18 (Videotape playback resumed.)
19 CROSS-EXAMINATION
20 BY MR. KRUMHOLZ:
21 (Witness sworn.)
22 Q (by Mr. McCauley) -- about additional here,
23 though, are we? We're talking about one that was down.
24 M9 was down; right?
25 A No.

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1 Q M9 was still working?
2 A During the annual survey, yes.
3 Q Do you believe in February of 1996 that M9 was
4 working as advertised, --
5 (Videotape playback paused.)
6 MR. KRUMHOLZ: Is that volume okay?
7 (Videotape playback resumed.)
8 Q (by Mr. McCauley) -- the way it was supposed
9 to be; is that right?
10 A That is my understanding.
11 Q And M8.5 was in the works as, as early as
12 February of 1996; is that correct?
13 A Yes.
14 Q And when you say "in the works", what does
15 that mean?
16 A That, that it had been identified; that AFES
17 had been written; that the -- what other processes have
18 to be done to install a new ground bed had, had begun.
19 Q So that the wheels were starting to turn
20 already in February; is that right?
21 A Yes, sir.
22 Q You know that you have to obtain a permit from
23 the State of Texas to do that, don't you?
24 A You have to obtain a couple of permits.
25 Q And who do you obtain those from?

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1 A From the Water Resources Board and the
2 Railroad Commission.
3 Q Would you identify for me what's, what's
4 marked as Exhibit 3 to your deposition, please?
5 A It is a memo from Alan Taylor to David Kilian
6 and myself.
7 Q Dated --
8 A -- February 19th, 1996.
9 Q Who wrote the handwritten portion at the
10 bottom of the memo?
11 A I did.
12 Q Read that, please.
13 A Met with Alan T., David K. on 2/20/96. Will
14 write AFE to replace ground bed or GB on 8-inch and
15 four on old 10-inch to see what it does. See Franklin,
16 2/24.
17 Q And you completed an AFE, in fact, and
18 submitted it on 2/26/96, which is marked as Exhibit 4
19 to your deposition; isn't that true?
20 A Yes.
21 Q Do you know why the applications didn't happen
22 for three months or more after your 2/26 submittal?
23 A The -- you have to go for the approval
24 process.
25 Q And what is that process?

A handwritten signature in black ink, consisting of a stylized 'S' followed by a large loop and a final flourish.

<div>REPORTER'S RECORD</div> <div>VOLUME 8 OF 24 VOLUMES</div> <div>TRIAL COURT CAUSE NO. 51458</div> <div>DANNY SMALLEY, INDIVIDUALLY) IN THE DISTRICT COURT</div> <div>AND AS INDEPENDENT)</div> <div>ADMINISTRATOR OF DANIELLE)</div> <div>DAWN SMALLEY, DECEASED)</div> <div>VS.) KAUFMAN COUNTY, TEXAS</div> <div>KOCH INDUSTRIES, INC., KOCH)</div> <div>PIPELINE COMPANY, L.P.,)</div> <div>KOCH HYDROCARBON COMPANY,)</div> <div>KPL/GP, INC., AND RONALD)</div> <div>GANT) 86TH JUDICIAL DISTRICT</div> <div>TRIAL ON MERITS</div> <div>On the 12th day of October, 1999, the following</div> <div>proceedings came on to be heard in the above-entitled</div> <div>And numbered cause before the Honorable Glen M.</div> <div>Ashworth, Judge presiding, held in Kaufman, Kaufman</div> <div>County, Texas:</div> <div>Proceedings reported by machine shorthand.</div>	<div>1 WITNESS INDEX</div> <div>2</div> <div>3 Voir</div> <div>4 Direct Cross Redirect Recross Dire</div> <div>5 ROGER</div> <div>6 FLOYD 5 45</div> <div>7</div> <div>8 DON</div> <div>9 CARSON 61 78</div> <div>10 82 111 144 167 178</div> <div>11 CHARLES</div> <div>12 POWELL 182 243</div> <div>13 245 245</div> <div>14 247</div> <div>15 ALPHABETICAL WITNESS INDEX</div> <div>16</div> <div>17 Voir</div> <div>18 Direct Cross Redirect Recross Dire</div> <div>19 DON</div> <div>20 CARSON 61 78</div> <div>21 82 111 144 167 178</div> <div>22 ROGER</div> <div>23 FLOYD 5 45</div> <div>24 CHARLES</div> <div>25 POWELL 182 243</div> <div>26 245 245</div> <div>27 247</div> <div>28 EXHIBIT INDEX</div> <div>29 PLAINTIFF'S DESCRIPTION OFFERED ADMITTED</div> <div>30 NO.</div> <div>31 48 Intercompany 11 11</div> <div>32 Koch Memo</div> <div>33 49 Intercompany 26 26</div> <div>34 Koch Memo</div> <div>35 50 Carlson's Roles, 66 67</div> <div>36 Responsibilities</div>
<div>1 APPEARANCES</div> <div>2</div> <div>3 Mr. Ted B. Lyon</div> <div>4 SBOT NO. 12741500</div> <div>5 Mr. Marquette Wolf</div> <div>6 SBOT NO. 00797685</div> <div>7 TED B. LYON & ASSOCIATES</div> <div>8 Town East Tower - Suite 525</div> <div>9 18601 LBJ Freeway</div> <div>10 Mesquite, Texas 75150</div> <div>11 Phone: (972)279-6571</div> <div>12 ATTORNEYS FOR PLAINTIFF</div> <div>13 -AND-</div> <div>14 Mr. R. Michael McCauley</div> <div>15 SBOT NO. 13383500</div> <div>16 McCauley, Macdonald, Devin & Huddleston</div> <div>17 3800 Renaissance Tower</div> <div>18 Dallas, Texas 75270-2014</div> <div>19 Phone: (214)744-3300</div> <div>20 ATTORNEY FOR PLAINTIFF</div> <div>21 -AND-</div> <div>22 Mr. Michael C. Steindorf</div> <div>23 SBOT NO. 19134800</div> <div>24 Mr. Richard S. Krumholz</div> <div>25 SBOT NO. 00784425</div> <div>26 Mr. Sean P. Brennan</div> <div>27 SBOT NO. 00787135</div> <div>28 FULBRIGHT & JAWORSKI</div> <div>29 2200 Ross Avenue, Suite 2800</div> <div>30 Dallas, Texas 75201</div> <div>31 Phone: (214)855-8022</div> <div>32 ATTORNEYS FOR DEFENDANTS</div> <div>33</div> <div>34</div> <div>35</div> <div>36</div>	<div>1 51 Pipeline Revision 81 82</div> <div>2 Report</div> <div>3 52 Pipeline Revision 81 84</div> <div>4 Report</div> <div>5 53 South Survey 86 86</div> <div>6 54 Bimonthly Rectifier 112 112</div> <div>7 Report</div> <div>8 55 Bimonthly Rectifier 141 141</div> <div>9 Report</div> <div>10 56 Bimonthly Rectifier 141 141</div> <div>11 Report</div> <div>12 57 Bimonthly Rectifier 141 141</div> <div>13 Report</div> <div>14 58 Bimonthly Rectifier 141 141</div> <div>15 Report</div> <div>16 59 Bimonthly Rectifier 141 141</div> <div>17 Report</div> <div>18 60 Monthly Power Usage 144 144</div> <div>19 61 Curriculum Vitae 187 187</div> <div>20 of Powell</div> <div>21 62 Unknown 237</div> <div>22 63 Vetco Presentation 251 251</div> <div>23 64 Round Chart 251 252</div> <div>24 EXHIBIT INDEX</div> <div>25 DEFENDANTS' DESCRIPTION OFFERED ADMITTED</div> <div>26 NO.</div> <div>27 23 Affidavit of 59 60</div> <div>28 Rhodes</div> <div>29 24 Pipeline Revision 147 147</div> <div>30 Report</div> <div>31 25 Pipeline Revision 148 149</div> <div>32 Report</div>

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1 PROCEEDINGS

2

3 (Jury ushered in.)

4 THE COURT: Thanks. Be seated, please.

5 Okay. We've got the walking wounded over

6 here. We got you sniffing now?

7 All right. Let me just tell you, as I

8 mentioned earlier -- I mean, I appreciate your efforts.

9 We all do, and you understand the importance of your

10 service. If you need extra breaks or you need to take

11 a little extra time, just let me know that. Okay.

12 Call your next witness.

13 MR. LYON: Your Honor, at this time, we

14 call Roger Floyd by deposition. He's the former

15 corrosion supervisor on this pipeline, currently head

16 of pipeline integrity for Koch, by video.

17 (Witness sworn.)

18 ROGER FLOYD,

19 having been first duly sworn, testified as follows by

20 videotape deposition:

21 DIRECT EXAMINATION

22 BY MR. LYON:

23 (Video playback begins.)

24 Q (by Mr. Wolf) When you'd write a memo like

25 this memo, this October 1st, 1990 memo, that would be

Page 6

1 in connection with your job at the time with Koch and

2 not on the committee; right?

3 A This memo relates to my job, not the

4 committee. That's correct.

5 Q And these are the types of memos that you

6 created in the ordinary course of business reports to

7 your superiors; correct?

8 A Yes, sir.

9 Q And at the time Kenny Dayton was your

10 superior; correct?

11 A Yes, sir.

12 Q Okay. And I've marked this as Exhibit No. 2

13 to your deposition. This is the memo from you to Kenny

14 Dayton on October 1st, 1990; correct?

15 A Yes, sir.

16 Q And this memo concerns cathodic protection

17 problems on Sterling and Line II, meaning -- and we

18 know that -- today, that's the Sterling I line;

19 correct?

20 A Yes, sir.

21 Q Are you familiar with the construction of that

22 pipeline, in the sense of how it was designed, where it

23 was designed to originate and destinate, the places

24 that the pipeline travels through, and the

25 characteristics of it: its diameter, its grade, that

Page 7

1 sort of thing?

2 A Yes.

3 Q All right. This pipeline was built in 1981;

4 correct?

5 A Yes, sir.

6 Q And this pipeline was bid out in sections to,

7 to various contractors; correct?

8 A Yes, sir.

9 Q In other words, how do you do that when you're

10 coating a pipeline like Sterling I, as it was

11 originally coated?

12 A It is applied -- the coating is applied in the

13 field over the ditch, as you lay the pipe.

14 Q And what other types of conditions --

15 environmental conditions can affect coating?

16 A Cleanliness of the pipe. Moisture.

17 Q Anything else?

18 A Wind.

19 Q Because that can affect the cleanliness?

20 A Yes, sir.

21 Q How can cleanliness affect the pipe, then,

22 while you're coating it?

23 A If a foreign substance is in the primer, it

24 will be adhered to the pipe. And it may cause a void

25 in the tape.

Page 8

1 Q And a void in the tape would be an area where

2 the tape is not protecting the pipe itself from

3 corrosion; correct?

4 A Potentially.

5 Q Potentially not protecting the pipe from

6 corrosion?

7 A It could be an area where the tape would not

8 have adhesion to the pipe or might even penetrate the

9 tape.

10 Q How can moisture affect the coating on the

11 pipeline?

12 A It can mix with the primer and either weaken

13 the primer or spot up on the primer and interfere with

14 adhesion.

15 Q What does "spot up on the primer" mean?

16 A Stay in a very confined area, like a drop of

17 water on the line or in the primer, and not mingle with

18 the primer. Just stay there.

19 Q Okay. And then if it weakens the primer,

20 what's the effect of that? If the moisture weakens the

21 primer, what effect does that have on the pipeline or

22 its coating?

23 A You will have a weaker adhesion between the

24 tape and the pipe.

25 Q Meaning that the pipe [sic] won't stick as

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1 Q You can do ten in a matter of weeks; correct?
2 That's one thing you can do on any pipeline.
3 A Depending on the situation.
4 Q You could do it if you had to; right?
5 A Again, depending on the situation.
6 Q What might keep you from doing something like
7 that? Would it be money?
8 A No, sir.
9 Q Is it possible in 1996, before this explosion
10 occurred, that Koch -- for Koch to put in two or three
11 new -- three new rectifiers in Kaufman County in a
12 matter of two months?
13 A Was it possible?
14 Q Yes, sir.
15 A Yes, sir.
16 Q Okay. Did you recommend Cary Fredrick be
17 appointed as the corrosion supervisor in 1991?
18 A Yes, sir.
19 Q Did you -- tell me your opinion of
20 Mr. Fredrick at that time, with regard to his knowledge
21 of corrosion engineering or corrosion issues that would
22 be faced by the Medford corrosion department.
23 A Cary was a very good field technician. He was
24 very knowledgeable in cathodic protection. He had been
25 to several training courses, and I believe he was

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1 NACE-certified.
2 Q So any concerns you had about Mr. Fredrick,
3 would it be fair to say, would be the same type of
4 concerns you would have about anyone who was for the
5 first time assuming a management position?
6 A From a management side, yes.
7 Q Did you have any other problems with
8 Mr. Fredrick? Or I shouldn't say problems. That's not
9 fair.
10 But any other concerns about him?
11 A No, sir.
12 Q Okay. Did you recommend that Alan Taylor
13 replace Cary Fredrick in 1993?
14 A No, sir.
15 Q Does Koch ever operate its pipelines with low
16 levels of cathodic protection consciously, knowingly?
17 A There may be a time when you have a, a
18 potential that does not meet criteria. And from the
19 time you find it until the time you can get it repaired
20 or get it up, you would know that it was low.
21 Q Are you familiar with how long it took to
22 replace M9?
23 A Yes, sir.
24 Q Had Sterling I in Kaufman County gone too long
25 without adequate or sufficient cathodic protection --

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1 sufficient, in the sense of meeting your criteria of
2 .850?
3 A The process had gone too long in getting it
4 back up, in getting the ground bed installed.
5 Q Why didn't Koch turn off that pipeline, after
6 five months of not having cathodic protection in the
7 area of the rupture site, after they know -- after they
8 knew that M9 had failed?
9 A I have not asked.
10 Q If that pipeline is not pushing product, is it
11 making money?
12 If it's just sitting there, not able to
13 deliver product, can it make money?
14 A I, I don't know that.
15 Q Does it make sense that it could make money
16 just sitting there, not being able to push product?
17 A I'm, I'm not an accountant. I can't tell you
18 what it makes or doesn't make, as far as that side of
19 it. I don't know.
20 Q Okay. You know that Koch had determined that
21 it needed another rectifier in Kaufman County, the one
22 that they were going to call M8.5, when they did it --
23 their annual survey in February of 1996; correct? When
24 the -- when the annual survey was reported.
25 A Yes, sir.

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1 Q You knew that at the time Koch figured out,
2 "We'd better put in M8.5," to raise their level of
3 cathodic protection -- you knew at that time, at the
4 moment that determination was made, M9 was also working
5 at that time?
6 A Yes, sir.
7 Q And you know that after they had decided they
8 needed M8.5, M9 then failed; right?
9 A Yes, sir.
10 Q So an area where they needed two rectifiers
11 and ground bed sets, they now had none; right?
12 A They needed to -- they were trying to
13 understand if 8.5 could do it by itself. They knew
14 ground bed installation.
15 Q And you know that April, May, June, July, and
16 almost all of August went by, and they never put either
17 8.5 on or fixed M9; right?
18 A Yes, sir.
19 Q And you know that corrosion could occur
20 without cathodic protection on that pipeline; right?
21 A Yes, sir.
22 (Video playback paused.)
23 MR. KRUMHOLZ: Your Honor, we have just
24 a few minutes of Mr. Floyd.
25 THE COURT: Okay.

39

REPORTER'S RECORD
VOLUME 7 OF 24 VOLUMES
TRIAL COURT CAUSE NO. 51458

DANNY SMALLEY, INDIVIDUALLY) IN THE DISTRICT COURT
AND AS INDEPENDENT)
ADMINISTRATOR OF DANIELLE)
DAWN SMALLEY, DECEASED)
VS.) KAUFMAN COUNTY, TEXAS
Koch Industries, Inc., Koch)
Pipeline Company, L.P.)
Koch Hydrocarbon Company,)
KPL/GP, Inc., and Ronald)
Gant) 86TH JUDICIAL DISTRICT

TRIAL ON MERITS

On the 11th day of October, 1999, the following
proceedings came on to be heard in the above-entitled
and numbered cause before the Honorable Glen M.
Ashworth, Judge presiding, held in Kaufman, Kaufman
County, Texas:
Proceedings reported by machine shorthand.

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EXHIBIT INDEX

PLAINTIFF'S NO.	DESCRIPTION	OFFERED	ADMITTED
32	Brown Engineering Hydrostatic Test	14	15
33	British Gas Results	16	
34	Pipeline Revision Report	22	22
35	Test Site to Corsicana (Revisions)	32	32

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1 THE COURT: Call your next witness.
2 MR. McCAULEY: Your Honor, at this point
3 plaintiffs would call by video deposition, play
4 portions of the deposition of Mr. Bill Caffey.
5 THE COURT: All right.
6 MR. McCAULEY: This deposition was taken
7 on about the 14th of April 1999, Your Honor. Here's a
8 copy for the Court along with page and line, although
9 this is highlighted as well.
10 (Witness sworn.)
11 BILLY RAY CAFFEY,
12 having been previously duly sworn, testified as follows
13 by videotape deposition:
14 DIRECT EXAMINATION
15 BY MR. McCAULEY:
16 (Video playback begins.)
17 Q Mr. Caffey, state your full name, please.
18 A It's Billy Ray Caffey.
19 Q I'm going to begin by asking you what your --
20 just to describe for the jury, please, what your
21 current job position is and with what company is
22 that -- that entails.
23 A I'm an executive vice president of
24 Koch Industries.
25 THE COURT: Down a little bit, just a

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1 touch.
2 Q (by Mr. McCauley) Do you serve as an officer
3 of any other corporation, whether a Koch corporation or
4 not?
5 A I don't believe so.
6 Q Are you a director of any corporation?
7 A Yes.
8 Q What corporations?
9 A I'm a director of several of the various
10 businesses and corporations that Koch has.
11 Q I've been provided what's marked Exhibit 1 to
12 your deposition, which is a 1996 version of your roles
13 and responsibilities and that, I believe, is dated
14 February what, 20, 20th, February 20th?
15 A Yes, sir.
16 Q If you would, obviously one of the areas we're
17 concerned about and interested in today is these kinds
18 of roles and responsibilities defined on page 12 under
19 operations capability team. In particularly, as it
20 starts at the top of page 3, would you just read that
21 under "Responsibility" that first heading?
22 A And you'd like for me to read the first corky
23 dot?
24 Q Well, where the bullet point is there.
25 A This one (indicating)?

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1 Q Uh-huh.
2 A It -- "Align our employee and manager vision
3 and incentives such that we ensure governmental and
4 legal compliance while significantly reducing our
5 environmental and safety accidents and their associated
6 cost.
7 Q Okay. How long prior to February of 1996 had
8 you deemed that or viewed that as one of your
9 responsibilities?
10 A I believe that's always been one of my
11 responsibilities.
12 Q And when you say "always," well, we don't mean
13 for eternity, what do you mean by that? Since you've
14 been with Koch or in this position or what?
15 A In some form or fashion depending on my level
16 of responsibility since I've been with Koch.
17 Q Since you've been Koch, that's always been an
18 area. It's just that as you rose in the ranks and the
19 structure of the company, it expanded your umbrella of
20 your coverage, would that be true? You had a broader
21 responsibility but always had the same kind of
22 responsibility?
23 A I believe that would be true.
24 Q Okay. And when did you first join Koch in any
25 capacity with any of their entities?

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1 A In May of 1973.
2 Q Then if you would, below where it says
3 expectation in carrying out that responsibility you
4 just read to us, just read the first one there to me,
5 if you would.
6 A First corky dot?
7 Q Uh-huh.
8 A "A vision of what we wish to accomplish in
9 both environmental and safety is clearly understood by
10 each employee."
11 Q Okay. And the next one?
12 A "Safety becomes a part of our everyday
13 culture."
14 Q Next one?
15 A "Measures are developed to scorecard and aid
16 in our discovery."
17 Q And the next one?
18 A "Companies approached best in class in their
19 associated businesses."
20 Q Go ahead and just read each one of them.
21 A "Our environmental inspection and model
22 facility audit programs are put in place. Leaks
23 continue to be reduced. Discover if knowledge is
24 available to previct [sic] -- predict events providing
25 reliability in lieu of maintenance; and minimize the

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Page 163

1 Q Some subdivision?

2 A All of us are.

3 Q In what way are you responsible?

4 A I mean, we all have a role that we play within
5 this company and this terrible accident happened, and
6 we're responsible for it.

7 Q In what way? How are you responsible for it?

8 A We made mistakes.

9 Q Tell me and the jury, please, what those
10 mistakes were.11 A Don Carson didn't report the lack of cathodic
12 protection on the pipeline. We didn't understand the
13 role that MIC corrosion plays and how fast it can
14 corrode. We didn't have procedures in place to take
15 care of that, and we hadn't trained on that because, to
16 my knowledge, the industry didn't know how fast that
17 could work.18 Q I'm asking you when Koch first learned of the
19 cathodic protection problems on Sterling I. To your
20 knowledge, as the number three man in this company, who
21 is the person that the board looks to as being
22 responsible to make sure the pipeline is safely
23 operated? When did Koch first learn there were
24 cathodic protection problems on the Sterling I pipeline
25 in the vicinity where Danielle Smalley died?

1 THE COURT: Well, now you've lost me.

2 MR. STEINDORF: Page 77. Right now the
3 videotape is playing the question that Mr. McCauley
4 began to ask on line 19 and he has skipped -- I would
5 contend that he has improperly skipped lines 15 through
6 18 which, in context, is necessary to understand this
7 passage of testimony.8 MR. MCCAULEY: Your Honor, I ask the
9 Court to read it. I don't think it is, Your Honor. I
10 think it just duplicates what was said.11 THE COURT: For purposes of optional
12 completeness, assuming that they're going to begin on
13 page 77, 19, you want to include -- you want to begin
14 it at line 15?

15 MR. STEINDORF: 15, right.

16 THE COURT: All right. Then you can read
17 question on line 15, answer on line 17, then we'll pick
18 up on line 19.19 MR. STEINDORF: Okay. Question on
20 line 15 by the lawyer asking the question, "I'm sorry.
21 I thought you said Mr. Carson didn't report.22 "Answer: He didn't report low cathodic
23 protection levels in 1995. I'm sorry."

24 THE COURT: All right.

25 MR. MCCAULEY: That's fine.

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Page 164

1 A I believe in 1995.

2 (Video playback paused.)

3 MR. STEINDORF: Your Honor, I make an
4 optional completeness objection here on page --

5 THE COURT: Where is it?

6 MR. STEINDORF: I can show you.

7 THE COURT: You can tell me page and
8 line.9 MR. STEINDORF: It's page 77, and if you
10 look at page 77, line 6 --

11 THE COURT: Uh-huh.

12 MR. STEINDORF: -- they ask a question,
13 when did Koch first learn --14 MR. MCCAULEY: Your Honor, I think we
15 might hold off on reading it. Let's do it the right
16 way.

17 THE COURT: Tell me what the page is.

18 MR. STEINDORF: Page 77.

19 THE COURT: 77, line 6 through --

20 MR. STEINDORF: The thing is my objection
21 is leaving out the question at line 15 and the answer
22 at line 7 and 8.23 MR. MCCAULEY: Your Honor, I haven't left
24 anything out yet, we're going clear down through the
25 deposition.1 Back up. The last question we talked
2 over.

3 (Video playback resumed.)

4 Q (by Mr. McCauley) When did Koch first learn
5 that there were cathodic protection problems on the
6 Sterling I pipeline near the vicinity where
7 Danielle Smalley died?

8 A I believe in 1995.

9 Q Who, to your understanding, reported that?

10 A I understand Don Carson.

11 Q Reported it? Found it and reported it?

12 A Found it and eventually reported it, yes.

13 Q Is it to your understanding that he delayed in
14 that reporting that he was -- when you say "finally
15 reported it," I mean, what do you mean by that?16 A I don't believe he reported it immediately,
17 and I don't believe he realized the significance of it.18 Q Now, with regard to MIC -- referring to
19 microbiologically influenced corrosion; is that
20 correct?

21 A Yes.

22 Q Do you know what that is?

23 A Other than in broad terms, no, I don't.

24 Q Well, did you know that as early as in the
25 late '80s that Conoco was marketing on the retail

In The Matter Of:

*Danny Smalley, et al v.
Koch Industries, Inc., et al*



*Billy R. Caffey
Vol. 1, April 14, 1999*

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Word Index included with this Min-U-Script®

[1] CAUSE NO. 51458
[2] DANNY SMALLEY, INDIVIDUALLY)IN THE DISTRICT COURT OF
and as INDEPENDENT)
[3] ADMINISTRATOR OF DANIELLE)
DAWN SMALLEY, DECEASED,)
[4] JUDY SMALLEY, KENNETH STONE,)
INDIVIDUALLY and as PERSONAL)
[5] REPRESENTATIVE OF THE ESTATE)
OF JASON KENNETH STONE,)
[6]
Plaintiffs,)
[7]
vs.)KAUFMAN COUNTY, TEXAS
[8]
KOCH INDUSTRIES, INC., KOCH)
[9] PIPELINE COMPANY, L.P.,)
KOCH HYDROCARBON COMPANY,)
[10] KPL/GP, INC., and RONALD)
GANT,)86TH JUDICIAL DISTRICT
[11]
Defendants.)VOLUME I
[12]
[13]
[14] Deposition of BILLY R. CAFFEY, taken by
[15] the Plaintiffs, before me, Janelle E. Goddard, a
[16] Certified Shorthand Reporter within and for the
[17] State of Kansas, at 4111 East 37th Street North,
[18] Wichita, Sedgwick County, Kansas, commencing at
[19] 9:25 a.m. on the 14th day of April, 1999.
[20]
[21] APPEARANCES
[22] Plaintiffs appear by their attorneys,
[23] R. Michael McCauley, McCauley, MacDonald & Devin,
[24] P.C., 3800 Renaissance Tower, 1201 Elm Street,
[25] Dallas, Texas 75270; and Marquette Wolf, Ted B.

Page 2

[1] APPEARANCES (Cont.)
[2] Lyon & Associates, 18601 LBJ Freeway, Suite 525,
[3] Mesquite, Texas 75150.
[4] Defendants, Koch Industries, Inc., Koch
[5] Pipeline Company, L.P., Koch Hydrocarbon Company,
[6] appear by their attorneys, Michael C. Steindorf,
[7] Fulbright & Jaworski, L.L.P., 2200 Ross Avenue,
[8] Suite 2800, Dallas, Texas 75201; and Mitchell L.
[9] Herren, Senior Counsel, Koch Industries, Inc.,
[10] Legal Department, 4111 East 37th Street North,
[11] P.O. Box 2256, Wichita, Kansas 67201-2256.
[12] Also present were Tannis Moore, Legal
[13] Assistant; and John Bazzelle, Kent Audio Visual.
[14]
[15]
[16]
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[24]
[25]

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[3] DIRECT
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[19] Memo dated 4-11-96 from Mr. Koch to various
people-Nos. JE 000719-720
[20]
[21] Reporter's Note: All exhibits attached to
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[22] deposition.
[23]
[24] CERTIFICATE OF REPORTER.....152
[25]

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[1] BILLY R. CAFFEY,
[2] having been first duly sworn, was
[3] examined and testified as follows:
[4]
[5] DIRECT-EXAMINATION
[6] BY MR. McCAULEY:
[7] Q: Mr. Caffey, state your full name, please.
[8] A: It's Billy Ray Caffey.
[9] Q: Let me begin by asking you what your - just
[10] to describe for the jury, please, what your
[11] current job position is and with what
[12] companies that - that entails.
[13] A: I'm an Executive Vice President of Koch
[14] Industries.
[15] Q: Do you serve as an officer of any other
[16] corporation, whether a Koch corporation or
[17] not?
[18] A: I - I don't believe so.
[19] Q: Are you a director of any corporation?
[20] A: Yes.
[21] Q: What corporations?
[22] A: I'm a director of several of the various
[23] businesses and corporations that Koch has.
[24] Q: Can you tell me which ones those are? Are you
[25] a director of Koch Industries, Inc.?

[1] (Marked for identification
[2] Deposition Exhibit Number 1.)
[3] BY MR. McCAULEY:
[4] Q: I've been provided with what's marked as
[5] Exhibit 1 to your deposition which is a 1996
[6] version of your roles and responsibilities and
[7] that I believe is dated February the what,
[8] 20 - 20th - February the 20th?
[9] A: Yes, sir.
[10] Q: It would - would it be true in your case as
[11] it is other employees of Koch that we've
[12] deposed that you prepare or at your direction
[13] the initial draft of that is prepared?
[14] A: That'd be true.
[15] Q: So what is marked as Exhibit 1 is your
[16] definition or your delineation of the roles
[17] and responsibilities that you had at that time
[18] as you perceived them and saw them; is that
[19] correct?
[20] A: That's correct.
[21] Q: And then would it also be true as with other
[22] employees that you then sit down with someone
[23] else above you to review those and talk about
[24] them and get feedback from the person senior
[25] to you?

Page 5

Page 7

[1] A: I am.
[2] Q: Okay. What else?
[3] A: I'm not certain I could give you the list off
[4] the top of my head, but I'm sure we could
[5] furnish that to you.
[6] Q: Is there some kind of an organizational chart
[7] or something that shows that? Shows who
[8] serves on the board and who serves as an
[9] officer of the various corporations?
[10] A: I don't believe there's an organizational
[11] chart, per se, but there would be a - a -
[12] Q: Or a memo that delineates those folks?
[13] A: I believe so.
[14] Q: So rather than sit here and try to enumerate
[15] each one, do you think maybe like during our
[16] lunch break or sometime you could lay your
[17] hands on that and save some time?
[18] A: I don't know if I could do it at lunch but I'm
[19] certain we could - we could lay our hands on
[20] it.
[21] Q: Okay. We'll come back to that then if we
[22] could try to find it during a break or
[23] something then.
[24] A: Okay.
[25] Q: Thank you.

[1] A: That's certainly true in my case, yes.
[2] Q: And who was that that you sat down with in
[3] evaluation and review of the 2-20-98, Exhibit
[4] Number 1?
[5] A: It would have been Bill Hanna.
[6] Q: What was Bill Hanna's position at that time?
[7] A: He is President of Koch Industries.
[8] Q: And still is; is that correct?
[9] A: That's correct.
[10] Q: And is he your immediate boss?
[11] A: He is.
[12] Q: Who is his boss?
[13] A: He reports to Charles Koch.
[14] Q: Okay. So that whenever he would sit down and
[15] prepare his roles and responsibilities, he
[16] would sit down with Charles Koch and review
[17] them, would that be true?
[18] A: That would be true.
[19] Q: If you would - obviously one of the areas
[20] that we're concerned about and interested in
[21] today is these kinds of roles and
[22] responsibilities defined on page two under
[23] Operations Capability Team. And particularly
[24] as it starts out the top of page three, would
[25] you just read that under Responsibility, that

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[1] **A:** And once again, Counselor, I've tried to
[2] answer that as best I can. Based on what he
[3] knew at the time, I think Don did as good a
[4] job as he could do.

[5] **BY MR. WOLF:**

[6] **Q:** I'm sure you think that, but I want to know do
[7] you approve of the way he did it or disapprove
[8] of it?

[9] **MR. STEINDORF:** I'm going to object
[10] to form and instruct you not to answer
[11] the question.

[12] **MR. WOLF:** On what basis?

[13] **MR. STEINDORF:** It's abusive,
[14] repetitive, repetitious.

[15] **MR. WOLF:** No, the objection to
[16] repetition -

[17] **MR. STEINDORF:** If you disagree -
[18] if you disagree with the abusive nature
[19] of it, then take it up with the Court.

[20] **MR. WOLF:** Well, I don't think
[21] there's any abusive nature. The
[22] objection would be asked and answered.
[23] He hasn't answered the question.

[24] **BY MR. WOLF:**

[25] **Q:** Simply, do you approve of it or disapprove of

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[1] it?

[2] **MR. STEINDORF:** Object to form and
[3] instruct you not to answer.

[4] **BY MR. WOLF:**

[5] **Q:** Are you going to answer my question or am I
[6] going to have to have you come down to Texas
[7] and do it?

[8] **A:** I'm not going to answer your question.

[9] **Q:** Okay. You received a bonus last - in 1997;
[10] is that correct?

[11] **A:** I did.

[12] **Q:** Did you receive a bonus in 1996?

[13] **A:** I did.

[14] **Q:** Hand you BC 25. In 1996, did you receive a
[15] bonus of \$900,000?

[16] **A:** I did.

[17] **Q:** Was that a bonus you received at the beginning
[18] of the year or at the end of the year?

[19] **A:** The 1996 bonus would have been awarded in
[20] March of 1997. Is that your question?

[21] **Q:** That answered my question. Similarly, when
[22] would the bonus from 1997 have been awarded?

[23] **A:** It would have been awarded in March of 19 -

[24] **Q:** '98?

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[1] **A:** '98.

[2] **Q:** And that was also \$900,000; correct?

[3] **A:** That's correct.

[4] **Q:** During any of your - strike that.

[5] Do your annual reviews where you

[6] discuss with Mr. Hanna your roles,

[7] responsibilities and expectations with Koch,

[8] do they look at your job performance over the

[9] prior or preceding year?

[10] **A:** The 1996 bonus would have been for my job
[11] performance in 1996.

[12] **Q:** The question is when you have your reviews

[13] with Mr. Hanna for your RRE's, roles,

[14] responsibilities and expectations, do the two

[15] of you discuss your performance over the prior

[16] year?

[17] **A:** No.

[18] **Q:** You don't? Do you ever discuss with Mr. Hanna

[19] your performance?

[20] **A:** Over the prior year?

[21] **Q:** Uh-huh.

[22] **A:** Yes.

[23] **Q:** Did you ever discuss your performance during

[24] 1996 with Mr. Hanna?

[25] **A:** I did.

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[1] **Q:** Does your performance during a given year as
[2] the number three man at Koch take into
[3] consideration the performance of the entities,
[4] the people, and the facilities under your
[5] control?

[6] **A:** It would.

[7] **Q:** Would that include Sterling I?

[8] **A:** It would.

[9] **Q:** During your review for the period of time that

[10] would have included the time of the explosion,

[11] was that explosion - was the operation and

[12] maintenance of Sterling I ever discussed?

[13] **A:** I don't believe so.

[14] **Q:** Okay. Do you recall what your bonus was in

[15] 1995? And I'll put in front of you another

[16] page from the payroll records. It's BC 26.

[17] **A:** Yes. Uh-huh.

[18] **Q:** What was your bonus in 1995?

[19] **A:** 450,000.

[20] **Q:** Okay. So it doubled in 1996.

[21] **A:** That's correct.

[22] **Q:** The 1996 bonus that you received in -

[23] actually in March of '97 was twice as much as

[24] the bonus you received in March of 1996;

[25] correct?

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- [1] **A:** That's correct.
[2] **Q:** Okay. But in the meantime, one of your
[3] assets - one of the assets you were
[4] responsible for as the number three man at
[5] Koch had a rupture and explosion and killed
[6] two people and that was never discussed in
[7] your review which touched and concerned your
[8] bonus for 1996; would that be correct?
[9] **A:** I don't believe we discussed that specifically
[10] in my review.
[11] **Q:** Okay. Do you have any plans of leaving Koch?
[12] **A:** Certainly.
[13] **Q:** When?
[14] **A:** I hope to retire some day.
[15] **Q:** When?
[16] **A:** I don't know.
[17] **Q:** Do you plan to - when you retire and quit
[18] working for good, do you plan to - to have
[19] Koch as your last place of employment?
[20] **A:** That would be my hope, yes.
[21] **Q:** Do you plan on working the next five years?
[22] **A:** Sure.
[23] **Q:** Ten? Do you plan on working the next ten
[24] years?
[25] **A:** I don't know if I can look out ten years.

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- [1] **Q:** How old are you?
[2] **A:** I am 47.
[3] **Q:** Do you plan on working until you're 65?
[4] **A:** No, sir.
[5] **Q:** Do you plan on working until you're 60?
[6] **A:** I don't know.
[7] **Q:** Just don't know?
[8] **A:** I don't know.
[9] **Q:** Do you know where Chuck Johnson is today?
[10] **A:** Yes, sir.
[11] **Q:** Where is he?
[12] **A:** I believe he's in Valley Center, Kansas. I
[13] mean unless he's gone, but that's where he
[14] lives.
[15] **Q:** Okay. How far is that from here?
[16] **A:** Gosh, a few miles.
[17] **Q:** Okay. When did he retire from Koch?
[18] **A:** Gosh, I'm not sure when Chuck retired.
[19] **Q:** In the past ten years?
[20] **A:** Oh, yeah.
[21] **Q:** Past five years?
[22] **A:** I believe so.
[23] **Q:** What was Chuck Johnson's position when he
[24] retired?
[25] **A:** Position when he retired I believe he was head

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- [1] of Chase Pipeline.
[2] **Q:** Did he ever come back to Koch after retiring
[3] to do some consulting?
[4] **A:** Chuck may have done some consulting work for
[5] us after he retired.
[6] **Q:** Have you had any dealings with the National
[7] Transportation and Safety Board concerning
[8] this case and their investigation of the
[9] Sterling I pipeline?
[10] **A:** Me personally?
[11] **Q:** Yes, sir.
[12] **A:** No, sir.
[13] **Q:** Okay. When was the first time you heard of
[14] MIC?
[15] **A:** I don't honestly know.
[16] **Q:** In the nineties?
[17] **A:** I honestly don't know, Counselor.
[18] **Q:** Okay. You do know that Koch plans to replace
[19] Sterling I pipeline through Kaufman County,
[20] don't you?
[21] **A:** Yes, sir.
[22] **Q:** When was that decision made?
[23] **A:** Probably first quarter of this year.
[24] **Q:** That decision required the signature of
[25] Charles Koch; correct?

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- [1] **A:** Doesn't require his signature. It requires
[2] his approval.
[3] **Q:** Approval.
[4] **A:** Okay.
[5] **Q:** Is that right?
[6] **A:** Sure.
[7] **Q:** All right. Do you agree with that decision to
[8] replace the 70 miles of the Sterling I
[9] pipeline between Nevada and Corsicana?
[10] **A:** I do.
[11] **Q:** Okay. Did anyone ever approach you during
[12] 1995 and suggest replacing the Sterling I
[13] pipeline section between Nevada and Corsicana?
[14] **A:** Not that I recall.
[15] **Q:** In order to do that, they would have to go
[16] through you, though; correct?
[17] **A:** Yeah, they would have had to have my approval,
[18] that's right.
[19] **Q:** During 1995 what was Jim Elmore's level of
[20] authority?
[21] **A:** Dollar-wise?
[22] **Q:** Dollar-wise.
[23] **A:** I don't know.
[24] **Q:** Okay. What was yours?
[25] **A:** 1995 it would have probably been - I'd have

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[1] talk to the witness again concerning
[2] questions that the attorney instructed
[3] him not to answer, we'll pass the
[4] witness.
[5] Additionally, Mike, if you
[6] could bring to that hearing on the 20th
[7] the originals you said of that
[8] four-in-one from that dig. What we were
[9] provided was a carbon copy with a pencil
[10] written-in portion as the original but it
[11] wasn't the original on those carbon
[12] sheets. We never actually saw the
[13] carbonless sheets of that document so, in
[14] other words, we haven't seen the
[15] original. We've seen a document that's
[16] photocopied then has in pencil that
[17] information and I think you and I are
[18] talking about two different versions of
[19] the term original, but it was David
[20] Augustus had called us down to your
[21] office, Tannis and I went over there, sat
[22] us in a conference room. He came in with
[23] an envelope and in the envelope is one
[24] sheet of paper and it was that. If you
[25] all can bring that to that hearing, I

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[1] would appreciate it.
[2] **MR. STEINDORF:** The sheet that David
[3] Augustus showed you you want us to bring.
[4] **MR. WOLF:** Which we were told was
[5] the original. If there's another
[6] original then that, too. We're talking
[7] about two different original versions of
[8] original but that's the one I'm talking
[9] about.
[10] **MR. STEINDORF:** Okay.
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[1] I, BILLY R. CAFFEY, the witness herein,
[2] have read the transcript of my testimony, and the
[3] same is true and correct to the best of my
[4] knowledge, with the exception of the changes noted
[5] on a separate page, together with notation of the
[6] reasons for making such corrections.
[7]
[8]
[9] **BILLY R. CAFFEY**
[10]
[11] STATE OF KANSAS)
) ss:
[12] SEDGWICK COUNTY)
[13] Subscribed and sworn to before me, the
[14] undersigned authority, this the ____ day of
[15] _____, 1999.
[16]
[17]
[18] Notary Public, _____ County
[19] State of Kansas
[20]
My appointment expires:
[21]
[22]
[23] Janelle E. Goddard, C.S.R.
[24]
[25]

Page 338

[1] **CERTIFICATE**
[2]
[3] STATE OF KANSAS)
) ss:
[4] SEDGWICK COUNTY)
[5]
[6] I, Janelle E. Goddard, certify that the
[7] foregoing deposition was stenographically recorded
[8] by me as stated in the caption. The deponent was
[9] duly sworn to tell the truth, the whole truth, and
[10] nothing but the truth. The colloquies, statements,
[11] questions and answers thereto were reduced to
[12] typewriting under my direction and supervision and
[13] the deposition is a true and correct record of the
[14] testimony/evidence given by the deponent.
[15] I further certify that I am not a
[16] relative or employee or attorney or counsel of any
[17] of the parties, nor am I a relative or employee of
[18] such attorney or counsel, nor am I financially
[19] interested in the action.
[20] **WITNESS** my hand and official seal at
[21] Wichita, Sedgwick County, Kansas, this 16th day of
[22] April, 1999.
[23]
[24] **JANELLE E. GODDARD, C.S.R.**
[24] **Certified Shorthand Reporter**
[25] **Costs:** _____

40

[illegible]

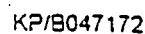
PROJECT TOTAL	<u>\$13,000.00</u>
REIMBURSABLE AMOUNT	<u> </u>
TOTAL CASH REQUIRED	\$13,000.00

APPROVED BY Jim DATE 2-26-96

APPROVED BY DK DATE _____

APPROVED BY _____ DATE _____

APPROVED BY _____ DATE _____



IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS

VOLUME 3 OF 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS

VOLUME 3 OF 5

41

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

AFFIDAVIT OF LINDA EADS

STATE OF TEXAS §
 §
COUNTY OF DALLAS §

Before me, the undersigned authority, on this day personally appeared Linda Eads, who being
by me duly sworn, deposed and said:

1. "My name is Linda Eads. I am over 21 years of age, have never been convicted of a felony, and am competent to make this affidavit. I have personal knowledge of the facts stated herein, and they are true and correct.

2. "I am a tenured Associate Professor of Law at Southern Methodist University, Dedman School of Law, in Dallas, Texas. I have taught at the Law School since January 1986.

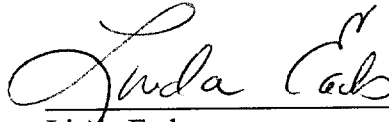
3. "From January 1999 to August 2000, I was on leave from the Law School in order to serve as Deputy Attorney General for Litigation for the State of Texas. During this time I supervised the State of Texas litigation against Koch Industries, Inc. and related Koch entities ("Koch") in the cases styled *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division, and *United States v. Koch Industries, Inc., et al.*, Civil Action No. 97-CV687B, United States District Court in the Northern District of Oklahoma.

4. "These cases involved Koch's violations of the federal Clean Water Act as a result of over 300 spills of crude oil from Koch's pipelines in the State of Texas and several other states.

5. "As the supervising attorney for the State of Texas, I am familiar with and have personal knowledge of the pleadings, documents and orders in the above-referenced cases. Attached in an Appendix to Plaintiff's Response to the Koch Defendants' Motion to Dismiss are true and correct copies of the following:

- a. The United States' Complaint and Revised Motion to Amend Schedule "A" to the Original Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division;
- b. The United States' Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. 97-CV687B, United States District Court in the Northern District of Oklahoma;
- c. Intervenor State of Texas' First Original Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division;
- d. Intervenor State of Texas' First Amended Original Complaint filed in *United States v. Koch Industries, Inc., et al.*, Civil Action No. 97-CV687B, United States District Court in the Northern District of Oklahoma;
- e. Expert Report of Rimkus Consulting Group, Inc. on behalf of the United States and State of Texas in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division;
- f. The Consent Decree filed and entered in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division;
- g. Portions of the Deposition Testimony of Edmond Murray, Jr. taken in *United States v. Koch Industries, Inc., et al.*, Civil Action No. H-95-1118, United States District Court for the Southern District of Texas, Houston Division; and
- h. Documents of the Texas Railroad Commission bates-stamped nos. RRCII 00862, RRCII 04613-04619, RRCII 00926, RRCII 02192-02441, RRCII 00886, and RRCII 00898."

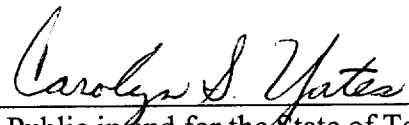
FURTHER AFFIANT SAYETH NOT.


Linda Eads

STATE OF TEXAS §
 §
COUNTY OF DALLAS §

SUBSCRIBED AND SWORN TO before me by the said Linda Eads on the 26th day of
September, 2001.




Notary Public in and for the State of Texas

My Commission Expires:

March 21, 2005

UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

Clerk, U.S. District Court
Southern District of Texas
FILED

APR 17 1995

UNITED STATES OF AMERICA,)
)
Plaintiff,)
v.)
)
KOCH INDUSTRIES, INC.,)
a/k/a KOCH OIL CO.,)
KOCH GATHERING SYSTEMS, INC.,)
KOCH GATEWAY PIPELINE CO.,)
successor to UNITED GAS)
PIPE LINE CO.,)
KOCH REFINING CO.,)
KOCH SERVICE, INC.,)
KOCH MATERIALS CO.,)
CHASE PIPELINE CO.,)
BOW PIPE LINE CO., INC.,)
CITRONELLE PIPELINE CO., INC.,)
)
Defendants.)
_____)

Michael N. Milby, Clerk of Court

Civil Action No.

H 95-1118

COMPLAINT

The United States of America, by the authority of the Attorney General of the United States and through the undersigned attorneys, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), and the United States Coast Guard, ("Coast Guard") through the Secretary of the Department of Transportation, files this complaint and alleges as follows:

I. INTRODUCTION

1. This is a civil action brought pursuant to the Clean Water Act ("CWA"), 33 U.S.C. § 1251 et seq., as amended by the Oil Pollution Act of 1990 ("OPA"), Pub. L. 101-380, 104 Stat. 484, seeking injunctive relief, civil penalties and recovery of oil pollution response costs incurred by the United States as a

result of the discharge of crude oil and petroleum products into navigable waters or adjoining shorelines of the United States.

II. JURISDICTION, VENUE AND NOTICE

2. This Court has jurisdiction over this action under 28 U.S.C. §§ 1331, 1345, 1355 and 1395(a); Sections 309(b) and 311(b)(7)(E) of the CWA, 33 U.S.C. §§ 1319(b) and 1321(b)(7)(E) and Sections 1002 and 1017(b) of the OPA, 33 U.S.C. §§2702, and 2717(b).

3. Authority to bring this action is vested in the United States Department of Justice by 28 U.S.C. §§ 516 and 519 and 33 U.S.C. § 1366.

4. Venue is proper in the Southern District of Texas pursuant to 28 U.S.C. §§ 1391 and 1395(a); Section 309(b) and 311(b)(7)(E) of the CWA, 33 U.S.C. §§ 1319(b) and 1321(b)(7)(E), inasmuch as it is the judicial district in which each defendant does business or has consented to personal jurisdiction.

5. Notice of the commencement of this action has been given to the States of Texas, Oklahoma, Kansas, Louisiana, Missouri and Alabama pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b).

III. DEFENDANTS

6. Defendant, Koch Industries, Inc., a/k/a Koch Oil Co., is a Kansas corporation with its principal place of business in Houston, Texas.

7. Koch Industries, Inc., a/k/a Koch Oil Co., is an "owner/operator" of an "onshore facility" and an "offshore

facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

8. Defendant, Koch Gathering Systems, Inc., is a Kansas corporation with its principal place of business in Houston, Texas.

9. Koch Gathering Systems, Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

10. Defendant, Koch Gateway Pipeline Co., is a Delaware corporation with its principal place of business in Houston, Texas.

11. Koch Gateway Pipeline Co. is the successor in interest to United Gas Pipeline Co.

12. Koch Gateway Pipeline Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

13. Defendant, Koch Refining Co., is a Delaware corporation with its principal place of business in Corpus Christi, Texas.

14. Koch Refining Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

15. Defendant, Koch Service, Inc., is a Kansas corporation that conducts business in Texas.

16. Koch Service, Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

17. Defendant, Koch Materials Co., is a Delaware corporation that conducts business in Texas.

18. Koch Materials Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

19. Defendant, Chase Pipeline Co., is a Kansas corporation that that has consented to personal jurisdiction in Texas.

20. Chase Pipeline Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning

of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

21. Defendant, Bow Pipe Line Co., Inc., is an Oklahoma corporation that has consented to personal jurisdiction in Texas.

22. Bow Pipe Line Co., Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

23. Defendant, Citronelle Pipeline Co., Inc., is a Kansas corporation whose parent corporation, Koch Gathering Systems, Inc., conducts business in Texas.

24. Citronelle Pipeline Co., Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

IV. THE CWA REGULATORY SCHEME FOR DISCHARGES OF OIL

Prohibition of Oil Discharges

25. Section 301(a) of the CWA, 33 U.S.C. § 1311(a), prohibits, except as otherwise authorized, the discharge of any pollutant, including oil, by any person. Section 502(12) of the

CWA, 33 U.S.C. 1362(12), defines "discharge of a pollutant" to include "any addition of any pollutant to navigable waters from any point source." Oil is a pollutant within the meaning of Section 502(6) of the CWA, 33 U.S.C. § 1362(6).

26. Section 311(b)(3) of the CWA, 33 U.S.C. § 1321(b)(3), prohibits the discharge of oil into or upon the navigable waters of the United States and adjoining shorelines in such quantities as the President determines may be harmful to the public health or welfare or environment of the United States.

27. Pursuant to Section 311(b)(4) of the CWA, 33 U.S.C. § 1321(b)(4), the President, through a delegation to EPA, Exec. Order No. 11735, 38 Fed. Reg. 21243 (Aug. 7, 1973), has determined by regulation that the quantities of oil that may be harmful to the public health or welfare or environment of the United States include discharges of oil that, inter alia, cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines. 40 C.F.R. § 110.3.

B. Injunctive Relief

28. Section 309(b) of the CWA, 33 U.S.C. § 1319(b), authorizes EPA to commence a civil action for appropriate relief, including a permanent or temporary injunction, for any violation for which he is authorized to issue a compliance order under [Section 309(a)]. [Bracketed material supplied.]

29. Section 309(a) of the CWA, 33 U.S.C. § 1319(a), authorizes, inter alia, the issuance of compliance orders for discharges of pollutants prohibited under Section 301(a) of the CWA, 33 U.S.C. 1311(a).

C. Civil Penalties

30. With respect to the discharges of oil alleged in Schedule A to this Complaint and which occurred prior to August 18, 1990, Section 309(d) of the CWA, 33 U.S.C. § 1319(d), provides, inter alia, that:

Any person who violates section 1311 [Section 301 of the CWA] ... shall be subject to a civil penalty not to exceed \$25,000 per day for each violation. [Bracketed material supplied.]

31. With respect to the discharges of oil alleged in Schedule A of this Complaint which occurred after August 18, 1990, Section 311(b)(7) of the CWA, 33 U.S.C. § 1321(b)(7), as amended by OPA, provides that:

Any person who is the owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged in violation of ... [Section 311(b)(3) of the CWA], shall be subject to a civil penalty in an amount up to \$25,000 per day of violation or an amount up to \$1,000 per barrel of oil or unit of reportable quantity of hazardous substances discharged. [Bracketed material supplied.]

V. FACTS GIVING RISE TO LIABILITY

32. The named defendants (collectively "Koch") own and operate underground crude oil pipelines and other onshore and offshore facilities throughout the states of Texas, Louisiana, Oklahoma, Kansas, Missouri and Alabama.

33. On numerous occasions in the past 5 years, (including but not limited to those spills specifically alleged in Schedule A to this Complaint) the defendants' pipelines and onshore and offshore facilities in the named states have ruptured causing oil and/or hazardous substances to spill into the environment and into the waters of the United States or the adjoining shorelines. These ruptures and spills are continuing. Appendix A to this Complaint lists the date, location (including county and state), affected waterway, and -if reported- the National Response Center report number of each spill.

VI. CLAIMS FOR RELIEF

A. First Claim: Injunctive Relief

34. Paragraphs 1 through 33 are realleged and incorporated by reference.

35. Defendants' discharge of oil and/or hazardous substances, into or upon the navigable waters of the United States or adjoining shorelines in such quantities as have been determined to be harmful to the public health or welfare or environment of the United States violate Section 311(b)(3) of the CWA, 33 U.S.C. § 1321(b)(3), and Section 301 of the CWA, 33 U.S.C. § 1311(a) and subjects defendants to injunctive relief pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b). Unless restrained by this Court, defendants will continue to discharge oil into the waters of the United States in violation of the CWA and OPA.

B. Second Claim: Civil Penalties

36. Paragraphs 1 through 33 are realleged and incorporated by reference.

37. Defendants' discharges of oil as alleged herein which occurred prior to August 18, 1990, violate Sections 301(a) and 311(b)(3) of the CWA, 33 U.S.C. §§ 1311(a) and 1321(b)(3) and, pursuant to Section 309(d) of the CWA subjects defendants to a civil penalty not to exceed \$25,000 per day for each violation.

38. Defendants' discharges of oil and/or hazardous substances as alleged herein which occurred after August 18, 1990, violate Sections 301(a) and 311(b)(3) of the CWA, 33 U.S.C. §§ 1311(a) and 1321(b)(3) and, pursuant to Section 311(b)(7)(A) of the CWA, 33 U.S.C. § 1321(b)(7)(A), subjects defendants to a civil penalty of up to \$1,000 per barrel of oil discharged.

39. Section 309(b) of the CWA, 33 U.S.C. § 1319(b), authorizes the commencement of a civil action for appropriate relief, including a permanent or temporary injunction. Unless restrained by this Court, defendants will continue to discharge oil in violation of the CWA and OPA.

PRAYER FOR RELIEF

WHEREFORE, plaintiff, the United States of America, respectfully requests that this Court enter judgment against the defendants for:

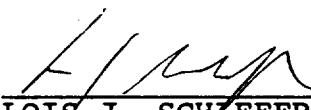
a. Such injunctive relief pursuant to Section 309(b) of the CWA as may be necessary to prevent future releases and protect and restore the waters of the United States; and

b. Impose civil penalties on defendants of up to \$25,000 per day for each discharge of oil occurring prior to August 18, 1990, for violations of Section 301(a) of the CWA and impose civil penalties on defendants of up to \$1,000 per barrel of oil discharged in violation of Section 311(b)(3) for all other spills alleged in the Complaint and all spills which occur or continue after the filing of this complaint;


c. Enter an Order requiring Koch to 1) report all spills of oil into waters of the United States to the National Response Center and 2) to accurately report the quantity of each spill.

d. Such other relief as the United States may be entitled.

Respectfully submitted,




LOIS J. SCHIFFER
Assistant Attorney General
Environment and Natural Resources
Division



ANGELA O'CONNELL
Trial Attorney
Environmental Enforcement Section
United States Department of Justice
P.O. Box 7611
Washington, DC 20044-7611
(202) 514-5315

GAYNELLE GRIFFIN JONES
United States Attorney


Gordon S. Young
Assistant United States Attorney

OF COUNSEL:

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Dallas, Texas 75202

Julie Van Horn
U.S. Environmental Protection Agency
Region VII
726 Minnesota Ave.
Kansas City, KS 66101

SCHEDULE A - ABBREVIATIONS**Defendants' Corporate Names**

KI = KOCH INDUSTRIES, INC.
 KO = KOCH OIL CO., a division of KOCH INDUSTRIES, INC.
 KGS = KOCH GATHERING SYSTEMS, INC.
 UGP = KOCH GATEWAY PIPELINE CO., successor to UNITED GAS PIPE LINE CO.
 KS = KOCH SERVICE, INC.
 KR = KOCH REFINING CO.
 KM = KOCH MATERIALS CO.
 BP = BOW PIPE LINE CO.
 CP = CHASE PIPELINE CO.
 CIT = CITRONELLE PIPELINE CO., INC.

States

AL = ALABAMA
 KS = KANSAS
 LA = LOUISIANA
 MO = MISSOURI
 OK = OKLAHOMA
 TX = TEXAS

- 1 -

SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
	CIT	NEAR THE END OF FOURTH STREET IN CITRONELLE, ALABAMA	MOBILE	AL	PUPPY CREEK	10/19/91
	CIT	CITRONELLE, ALABAMA	MOBILE	AL	PUPPY CREEK	01/24/92
	KGS	CITRONELLE, ALABAMA	MOBILE	AL	LITTLE CREEK	08/04/92
249208	KGS	RUSSELL ROAD, CITRONELLE, ALABAMA, SOUTH OF MARKS LANE	MOBILE	AL	PUPPY CREEK / SPRING	07/14/9
	CIT	CITRONELL, ALABAMA	MOBILE	AL	UNNAMED TRIBUTARY	09/26/94
264809	KM	4915 CHELSEA STREET KANSAS CITY, MO	JACKSON	MO	LITTLE BLUE RIVER	10/11/94
	KGS	QTR. SE, SEC. 26, T-14S, R-27W	GROVE	KS	UNNAMED CREEK > SMOKY CREEK POND	02/05/91
	KGS	QTR. SE, SEC. 4, T-14S, R-15W	RUSSELL	KS	UNNAMED CREEK	03/18/91
110633	KS	QTR. NE, SEC. 28, T-21S, R-11W	STAFFORD	KS	BIG SALT MARSH (WETLAND) IN QUIVIRA NATIONAL WILDLIFE REFUGE > RATTLESNAKE CREEK > ARKANSAS RIVER	03/13/92
	KGS	QTR. SW, SEC. 1, T-12S, R-18W	ELLSWORTH	KS	UNNAMED CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	10/12/92
	KGS	QTR. NE, SEC. 8, T-16S, R-10W	ELLSWORTH	KS	UNNAMED CREEK > WOLF CREEK > SMOKY HILL RIVER > KANSAS RIVER	12/23/92
	KGS	QTR. NW, SEC. 33, T-11S, R-19W	ELLIS	KS	UNNAMED INTERMITTENT STREAM	02/03/93
	KGS	QTR. NW, SEC. 23, T-10S, R-15W	OSBORNE	KS	UNNAMED POND > PARADISE CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	03/06/93
	KGS	QTR. SE, SEC. 18, T-20S, R-15W	BARTON	KS	UNNAMED POND > UNNAMED CREEK > DRY WALNUT CREEK > ARKANSAS RIVER	03/29/93

2 -

SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
	KGS	QTR. NW, SEC. 19, T-12S, R-15W	RUSSELL	KS	UNNAMED CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	04/19/93
	KGS	QTR. SE, SEC. 31, T-11S, R-20W	ELLIS	KS	SPRING CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	05/22/93
	KGS	QTR. SE, SEC. 8, T-15S, R-12W	RUSSELL	KS	BAR DITCH > UNNAMED CREEK > SMOKY HILL RIVER > KANSAS RIVER	05/30/93
	KGS	QTR. NW, SEC. 10, T-10S, R-19W	ROOKS	KS	BAR DITCH > DEPRESSION > SAND CREEK SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER (A.K.A. KAW RIVER)	06/02/93
	KGS	QTR. NW, SEC. 16, T-10S, R-15W	OSBORNE	KS	BAR DITCH > PARADISE CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	07/13/93
	KGS	QTR. SE, SEC. 18, T-20S, R-15W	BARTON	KS	UNNAMED POND > UNNAMED CREEK > DRY WALNUT CREEK > WALNUT CREEK > ARKANSAS RIVER	07/23/93
	KGS	QTR. SE, SEC. 31, T-11S, R-20W	ELLIS	KS	SPRING CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	08/27/93
	KGS	QTR. NW, SEC. 15, T-15S, R-18W	ELLIS	KS	TWO UNNAMED PONDS > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	09/01/93
	KGS	QTR. NE, SEC. 15, T-11S, R-19W	ELLIS	KS	UNNAMED INTERMITTENT STREAM > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	09/10/93
	KGS	QTR. NW, SEC. 31, T-11S, R-12W	ELLIS	KS	POND	09/15/93
	KGS	QTR. NE, SEC. 36, T-10S, R-19W	ROOKS	KS	SAND CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	09/25/93
	KGS	QTR. SE, SEC. 6, T-17S, R-19W	RUSH	KS	UNNAMED DRAW > BIG TIMBER CREEK > SMOKY HILL RIVER > KANSAS RIVER	10/04/93

SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
	KGS	QTR. SW, SEC. 27, T-16S, R-10W	ELLSWORTH	KS	PLUM CREEK > COW CREEK > ARKANSAS RIVER	11/18/93
212092	KGS	QTR. SW, SEC. 27, T-16S, R-10W	ELLSWORTH	KS	PLUM CREEK > COW CREEK > ARKANSAS RIVER	12/10/93
212808	KGS	QTR. SE, SEC. 5, T-12S, R-17W	ELLIS	KS	UNNAMED CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	12/15/93
216801	KGS	18 MILES NE OF HAYS SEC. 1, T-12S, R-18W	RUSSELL	KS	UNNAMED CREEK	01/14/9
234684	KGS	SEC. 12, T-11S, R-18	ELLIS	KS	UNNAMED CREEK	04/13/94
241964	CP	QTR. NE/NE/NE, SEC. 8, T-26, R-2E	SEDGWICK	KS	NORMALLY DRY CREEK	06/02/94
247493	KGS	SEC. 15, T-6S, R-22W	GRAHAM	KS	UNNAMED TRIBUTARY TO BOW CREEK	07/04/94
263945	KGS	SEC. 27, T-16, R-10W	ELLSWORTH	KS	DRY CREEK	10/05/94
278002	KGS	SEC. 7, T-12S, R-15W, 14 MILES NW OF GORHAM	RUSSELL	KS	WORTH CREEK	01/29/95
281654	KGS	SEC. 4, T-14S, R-15W, 1.5 MILES SE OF GORHAM, KS	RUSSELL	KS	STREAM	03/01/95
40155	KGS		ST. JAMES	LA	MISSISSIPPI RIVER	09/20/90
49954	KS	INTRACOASTAL WWY CANAL	TERREBONNE	LA	INTRACOASTAL WWY CANAL	12/04/9
58739	KGS	KOCH GATHERING FACILITY LAKE LONG STATION MILE MARKER 48.8	LAFOURCHE ST. JAMES	LA	INTRACOASTAL WWY	02/09/91
170963	KGS	BAYOU BLUE OIL FIELD 15 MILES S OF GROSSE TETE	IBERVILLE	LA	MARSH AREA > UPPER GRAND RIVER, WETLAND NEAR BAYOU RICHARD	05/02/93
	KO	MISTIC BAYOU FIELD	ST MARTIN	LA		02/16/94

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
269964 F95-0667	KGS	4 MILES EAST OF 79 ON ALTERNATE 2, EAST HAYNESVILLE FIELD	CLAIBORNE	LA	REEDER CREEK	11/16/94
18146	KGS	QTR. SE, SEC. 32, R-5N, R-5E	PONTOTOC	OK	UNNAMED POND	04/20/90
19391	KGS	QTR. SW, SEC. 19, T-1S, R-2W TATUM STATION	CARTER	OK	STREAM	04/27/90
19433	KGS	QTR. SE, SEC. 10, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK TRIBUTARY > MUD CREEK	04/27/9
	KGS	QTR. SE, SEC. 6, T-2S, R-4W	STEPHENS	OK	UNNAMED CREEK	04/30/90
20378	KGS	QTR. SE, SEC. 26, T-5N, R-4E	PONTOTOC	OK	UNNAMED CREEK > SOUTH CANADIAN RIVER	05/03/90
20532	KGS	QTR. NE, SEC. 2, T-9N, R-4E	POTTAWATOMIE	OK	UNNAMED CREEK > NEIGHBORS STOCK POND	05/04/90
20634	KGS	QTR. SW, SEC. 4, T-1S, R-3W	CARTER	OK	SANDY BEAR > WILD HORSE CREEK > WARHITA RIVER > TEXOMAH	05/05/90
20680	KGS	7 MILES DOWNSTREAM OF DENISON DAM ON RED RIVER	BRYAN	OK	RED RIVER	05/05/90
21240	KGS	QTR. SE, SEC. 3, T-2N, R-8W	STEPHENS	OK	UNNAMED STREAM > BEAVER CREEK	05/09/90
21184	KGS	QTR. NE, SEC. 21, T-6N, R-6E	SEMINOLE	OK	UNNAMED CREEK	05/09/90
21501	BP	QTR. NE, SEC. 22, T-24N, R-8E	OSAGE	OK	UNNAMED CREEK > HOMINY CREEK	05/10/9
23854	KGS	SEC. 35, T-5N, R-4E	PONTOTOC	OK	UNNAMED CREEK	05/25/90
24392	BP	QTR. NW, SEC. 35, T-27N, R-15E	NOWATA	OK	CALIFORNIA CREEK	05/29/90
24377	BP	QTR. SW, SEC. 2, T-17N, R-12E	TULSA	OK	UNNAMED CREEK	05/29/90
24650	BP	QTR. NW, SEC. 18, T-27N, R-15E	NOWATA	OK	UNNAMED STREAM	05/30/90
	KGS	QTR. SE, SEC. 12, T-1S, R-4W	STEPHENS	OK	SWAMPY AREA	05/30/90

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
25363	BP	QTR. NE/SW, SEC. 33, T-21N, R-12E HWY 75	OSAGE	OK	CREEK > UNNAMED RIVER	06/04/90
26995	KGS	QTR. NE, SEC. 29, T-6S, R-2E	LOVE	OK	CREEK > LAKE	06/15/90
27000	KGS	SEC. 33, T-5N, R-5E	PONTOTOC	OK	BUCKHORN CREEK	06/15/90
28205	KGS	QTR. SW/NW, SEC. 8, T-1N, R-3W	GARVIN	OK	STOCK POND	06/23/90
28735	KGS	QTR. NE, SEC. 13, T-8N, R-6E	SEMINOLE	OK	UNNAMED CREEK	06/28/90
	KGS	QTR. NW, SEC. 3, T-5N, R-4E	PONTOTOC	OK	SMALL UNNAMED STREAM	07/23/90
32347	KGS	QTR. NE, SEC. 36, T-5N, R-4E	PONTOTOC	OK	GROUND > 2 SMALL PONDS	07/24/90
	BP	QTR. NW, SEC. 25, T-23N, R-7E	OSAGE	OK	SMALL CREEK	09/24/90
41047	KGS	QTR. SE, SEC. 30, T-5N, R-7E	PONTOTOC	OK	UNNAMED CREEK	09/25/90
	KGS	QTR. NW, SEC. 2, T-2S, R-5W	STEPHENS	OK	TRIBUTARY, UNNAMED CREEK	11/05/90
	BP	QTR. NE, SEC. 3, T-24N, R-11E	OSAGE	OK	DOG THRASHER CREEK	11/12/90
	KGS	QTR. NE, SEC. 26, T-5S, R-1E	CARTER	OK	HICKORY CREEK	12/26/90
	KGS	QTR. SE, SEC. 27, T-1S, R-5W	STEPHENS	OK	UNNAMED CREEK	12/28/90
53188	KGS	SEC. 32, T-1S, R-6W	STEPHENS	OK	MUD CREEK	01/01/91
53333	BP	QTR. SE, SEC. 4, T-24N, R-11E	OSAGE	OK	DOG THRASHER CREEK	01/02/91
	KGS	T-4S, R-3W	CARTER	OK	WALNUT CREEK / SWAMPY AREA	01/07/91
54518	BP	QTR. NW, SEC. 8, T-25N, R-6E	OSAGE	OK	UNNAMED CREEK	01/10/91
56446	KGS	QTR. NE, SEC. 30, T-5N, R-5E (QTR. NW, SEC. 35) HWY 3	PONTOTOC	OK	UNNAMED CREEK LEADING TO SOUTH CANADIAN RIVER	01/24/91

SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
58308	BP	QTR. SW, SEC. 5, T-27N, R-8E	OSAGE	OK	UNNAMED CREEK	02/05/91
59349	KGS	QTR. SW, SEC. 1, T-15N, R-3E	LINCOLN	OK	UNNAMED CREEK	02/13/91
60642	BP	QTR. NE, SEC. 32, T-23N, R-11E	OSAGE	OK	DITCH > UNNAMED CREEK > HOMINY CREEK	02/20/91
	BP	QTR. SW, SEC. 3, T-20N, R-8E	PAWNEE	OK	UNNAMED CREEK	02/26/91
	KGS	QTR. NW, SEC. 21, T-3N, R-5W	GRADY	OK	TRIBUTARY OF RUSH CREEK	02/27/91
	KGS	QTR. SW, SEC. 29, T-1S, R-2W	CARTER	OK	UNNAMED CREEK	03/11/91
67710	KGS	SEC. 20, 21, T-3N, R-5W EATS ON 29, 1/2 MILE FROM COX CITY, THEN SOUTH	GRADY	OK	RUSH CREEK	04/12/91
	KGS	QTR. NW, SEC. 1, T-2S, R-4W	STEPHENS	OK	UNNAMED CREEK	04/29/91
	KGS	QTR. NW, SEC. 8, T-3N, R-5W	GRADY	OK	POND / CREEK / "SOIL LAKE"	05/06/91
72628	KGS	SEC. 7, T-22N, R-8E	OSAGE	OK	UNNAMED CREEK > KEYSTONE LAKE	05/19/91
74569	KGS	QTR. SW, SEC. 31, T-17N, R-3E	LINCOLN	OK	UNNAMED CREEK	06/05/91
	KGS	QTR. SW, SEC. 16, T-2S, R-2W	CARTER	OK	STREAM / CREEK	06/10/91
75277	KGS	QTR. NE/SE, SEC. 30, T-25N, R-11E	OSAGE	OK	UNNAMED STREAM	06/11/91
75573	KGS	QTR. NW, SEC. 21, T-25N, R-9E	OSAGE	OK	UNNAMED STREAM	06/12/91
	KGS	QTR. SW, SEC. 15, T-28N, R-7E	OSAGE	OK	CREEK	06/26/91
79168	KGS	QTR. NE, SEC. 27, T-21N, R-6W SOUTH EDGE OF WYKOMIS OFF COUNTRY RD	GARFIELD	OK	UNNAMED CREEK	07/11/91
81290	KGS	QTR. SE, SEC. 7, T-1S, R-3W	CARTER	OK	UNNAMED TRIBUTARY TO WILD HORSE CREEK	07/28/91

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
88655 85556	KGS	QTR. SE/SW, SEC. 33, T-24N, R-8E	OSAGE	OK	UNNAMED CREEK, TRIBUTARY TO HOMINY CREEK	08/26/91
86380	KGS	QTR. SE, SEC. 7, T-6N, R-5E	HUGHES	OK	SMALL CREEK	08/30/91
88393	KGS	QTR. NW, SEC. 2, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK	09/15/91
89021	KGS	QTR. SE, SEC. 19, T-4S, R-5W	CARTER	OK	UNNAMED CREEK	09/19/91
90163	KGS	QTR. NW, SEC. 19, T-7N, R-2W	CLEVELAND	OK	SMALL UNNAMED STREAM	09/28/91
	KGS	QTR. SE, SEC. 10, T-1S, R-4W QTR. NE, SEC. 27, T-1N, R-5W	STEPHENS	OK	DRY CREEK	09/29/91
	KGS	QTR. NE, SEC. 27, T-3N, R-5W	GRADY	OK	SMALL UNNAMED CREEK	09/30/91
92168	KGS		OSAGE	OK	CLEAR CREEK	10/14/91
92430	KGS	QTR. SW, SEC. 26, T-5N, R-4W	MCCLAIN	OK	UNNAMED CONSERVATION LAKE USED FOR FLOOD CONTROL	10/16/91
93350	KGS	SEC. 21, T-5N, R-5E	PONTOTOC	OK	TRIBUTARY > BUCKHORN CREEK	10/22/91
94493	KGS	QTR. NE, SEC. 33, T-1S, R-5W	STEPHENS	OK	SMALL UNNAMED CREEK	10/30/91
94603	KGS	QTR. SE/NW, SEC. 31, T-4S, R-10E	ATOKA	OK	UNNAMED CREEK > BOGGY CREEK	10/31/91
95401 F92-0407	KGS	QTR. SW/SW, SEC. 14, T-24N, R-10E	OSAGE	OK	UNNAMED CREEK	11/06
	KGS	QTR. SE/NW, SEC. 31, T-4S, R-10E	ATOKA	OK	BOGGY CREEK	11/06/91
98169	KGS	QTR. SE, SEC. 19, T-21N, R-9E	OSAGE	OK	SMALL CREEK	12/03/91
98643	KGS	QTR. SW, SEC. 29, T-1S, R-2W	CARTER	OK	UNNAMED CREEK AND SOIL	12/06/91
	KGS	QTR. NE, SEC. 20, T-2S, R-7W	STEPHENS	OK	UNNAMED CREEK	12/17/91
100328	KGS	QTR. SE, SEC. 33, T-6N, R-6E	SEMINOLE	OK	JUMPER CREEK	12/19/91

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
100322	KGS	SEC. 14, T-8S, R-8E	BRYAN	OK	UNNAMED CREEK	12/19/91
100532	KGS	QTR. SW, SEC. 17, T-3N, R-5W	GRADY	OK	RUSH CREEK	12/20/91
100509 100714	KGS	QTR. NE, SEC. 16, T-24N, R-7E QTR. NW, SEC. 29, T-24N, R-8E	OSAGE	OK	WET WEATHER CREEK / HOMINY CREEK	12/20/91
100834	KGS	SEC. 18, T-6N, R-8E	SEMINOLE	OK	CREEK > 3 1/4 MILE DOWN SMALL CREEK	12/25/91
100994	KGS	QTR. SE, SEC. 13, T-22N, R-11E	OSAGE	OK	QUAPAW CREEK	12/27/91
101280	KGS	NW QUARTER OF SECTION 24	STEPHENS	OK	UNNAMED CREEK	12/31/91
101409	KGS	QTR. SE, SEC. 16, T-25N, R-8E 15 MILES NW PAWHUSKA	OSAGE	OK	UNNAMED CREEK LEADING TO CLEAR CREEK	01/02/92
101750	KGS	QTR. NE, SEC. 36, T-23N, R-7E	OSAGE	OK	UNNAMED CREEK	01/06/92
103507	KGS	QTR. NE, SEC. 8, T-22N, R-8E CENTER OF THE S 1/2, SEC. 25, T-24N, R-7E	OSAGE	OK	WET/DRY CREEK BED	01/17/92
103508	KGS	QTR. NW, SEC. 5, T-25N, R-11E	OSAGE	OK	DRAINAGE DITCH > STREAM	01/18/92
103690	KGS	SEC. 24, T-25N, R-11E	OSAGE	OK	UNNAMED CREEK	01/20/92
104084	KGS	QTR. NE, SEC. 18, T-5S, T-1E	CARTER	OK	UNNAMED CREEK	01/22/92
104423	KGS	SEC. 24, T-21N, R-15W 25 MILES W OF FAIRVIEW	MAJOR	OK	UNNAMED CREEK	01/24/92
	KGS	QTR. NE/NE, SEC. 12, T-3N, R-3W	GARVIN	OK	STREAM AND SWAMPY AREA / LOW-LYING AREA / UNNAMED TRIBUTARY > RUSH CREEK	02/01/92
107608	KGS	QTR. SW, SEC. 24, T-5S, R-6W	MARSHALL	OK	SMALL POND	02/20/92
107950	KGS	QTR. SW, SEC. 35, T-5S, R-8E	BRYAN	OK	UNNAMED CREEK	02/24/92
108189	KGS	SEC. 11, T-6S, R-9E	BRYAN	OK	BLUE RIVER	02/25/92

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
121109	KGS	QTR. NW, SEC. 29, T-1S, R-5W	STEPHENS	OK	STOCK POND	06/09/92
122563	KGS	QTR. NW, SEC. 24, T-24N, R-16E	ROGERS	OK	UNKNOWN CREEK	06/18/92
122836	KGS	QTR. NW, SEC. 22, T-17N, R-4E	LINCOLN	OK	SMALL UNNAMED CREEK	06/20/92
122788	KGS	SEC. 21, T-8N, R-3W	CLEVELAND	OK	UNNAMED POND	06/20/92
123186	KGS	SEC. 14, T-1S, R-4W	STEPHENS	OK	UNNAMED CREEK TRIBUTARY > WILD HORSE CREEK	06/23/92
123468	KGS	SEC. 29, T-24N, R-12E	OSAGE	OK	UNNAMED TRIBUTARY > CANDY CREEK	06/24/92
123526 F92-3144	KGS	QTR. SW, SEC. 27, T-1S, R-3W, HWY 76	CARTER	OK	UNNAMED CREEK > WILD HORSE CREEK	06/25/92
126596	KGS	QTR. SW/SW, SEC. 19, T-14N, R-2E	LINCOLN	OK	SOIL AND UNNAMED CREEK	07/14/92
127445	KGS	QTR. SE, SEC. 20, T-6N, R-6E	SEMINOLE	OK	UNNAMED CREEK	07/18/92
130827 F92-3674	KGS	QTR. NW, SEC. 29, T-24N, R-8E	OSAGE	OK	NATURAL STREAM > POND > HOMINY CREEK	08/07/92
132975	KGS	SEC. 3, T-7N, R-3E	POTTAWATOMIE	OK	FARM POND	08/21/92
132965	KGS	QTR. NE, SEC. 7, T-2S, R-2W	CARTER	OK	RUSSELL PETTY BRANCH CREEK	08/21/92
136422	KGS	QTR. SW, SEC. 26, R-5E, T-7S	MARSHALL	OK	SANDY CREEK > LAKE TEXHOMA	09/12/92
142755	KGS	QTR. SW, SEC. 33, T-20N, R-8E (QTR. SE, SEC. 32)	PAWNEE	OK	HORSE CREEK	10/30/92
	KGS	QTR. SW, SEC. 36, T-1S, R-5W	STEPHENS	OK	CREEK	11/02/92
144442	KGS	QTR. SW, SEC. 34, T-19N, R-4E STATE HWY 99 BRIDGE	PAYNE	OK	UNNAMED CREEK > CIMMARON RIVER	11/11/92
	KGS	QTR. SW, SEC. 1, T-1S, R-4W	STEPHENS	OK	DRY CREEK	11/30/92

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
149130 148963	KGS	QTR. NW, SEC. 15, T-16N, R-5E 1.10 MILES S OF AVERY	LINCOLN	OK	POND AND UNNAMED CREEK	12/13/92
	KGS	QTR. SW/SE, SEC. 17, T-21N, R-8E	PAWNEE	OK	TRIBUTARY	12/28/92
151016	KGS	QTR. NW, SEC. 11, T-25N, R-9E	OSAGE	OK	UNNAMED CREEK	12/30/92
F93-0939	KGS	SEC. 13, T-21N, R-12E	TULSA	OK	TRIBUTARY OF BIRD CREEK	12/30/92
152339	KGS	QTR. NE, SEC. 13, T-21N, R-12E	TULSA	OK	STREAM	01/08/93
154217	KGS	QTR. NE, SEC. 28, T-5N, R-4W	MCCLAIN	OK	UNNAMED CREEK > LINDSAY LAKE	01/20/93
	KGS	QTR. SW, SEC. 6, T-4N, R-7W	GRADY	OK	POND	01/27/93
156537	KGS	QTR. NW, SEC. 20, T-22N, R-9E 3 MILES SE OF HOMINY	OSAGE	OK	UNNAMED STREAM	02/04/93
157228	KGS	QTR. NW, SEC. 13, T-6N, R-5E	POTTAWATOMIE SEMINOLE	OK	UNNAMED CREEK NEAR BEAVER DAM	02/09/93
157454 F93-1456	KGS	QTR. SE, SEC. 31, T-1N, R-9W	STEPHENS	OK	STAGE STAND CREEK	02/10/93
157878	KGS	SEC. 29, T-5S, R-7E	MARSHALL	OK	UNNAMED CREEK	02/12/93
158885	KGS	QTR. SW, SEC. 18, T-22N, R-11E	OSAGE	OK	STOCK POND	02/19/93
160587	KGS	QTR. SW, SEC. 32, T-2S, R-2W	STEPHENS	OK	UNNAMED CREEK	03/03/93
162617	KGS	QTR. NE, SEC. 20, T-2S, R-7W 1.5 MILES E, THEN .5 MILES N, THEN .5 MILES W OF COMANCHE	STEPHENS	OK	SMALL UNNAMED CREEK	03/17/93
163527 F93-1935	KGS	QTR. SE, SEC. 2, T-2N, R-3W 2 MILES SE OF PRUITT	CARTER	OK	UNNAMED CREEK > CONSERVATION LAKE	03/22/93

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
163617 F93-1940	KGS	QTR. SW, SEC. 9, T-2S, R-2W	CARTER	OK	UNNAMED CREEK	03/23/93
163846 F93-1956	KGS	SEC. 1, T-10N, R-8W HWY 81 RIVER BRIDGE NORTH OF MINCO SEC. 18, T-10N, R-5W	GRADY	OK	SOUTH CANADIAN RIVER	03/24/93
164515	KGS	QTR. SE, SEC. 10, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK	03/28/93
	KGS	ONE MILE SOUTH OF NORMAN WASTEWATER TREATMENT PLANT ON SOUTH CANADIAN RIVER AND WEST OF ASPHALT PLANT, STRAIGHT EAST OF DAVID J. PERRY AIRPORT QTR. NW, SEC. 20, T-8N, R-2W SEC. 17, T-8N, R-2W	CLEVELAND	OK	SOUTH CANADIAN RIVER	05/19/93
	KGS	QTR. SW, SEC. 15, T-17N, R-5E	PAYNE	OK	DRY CREEK BED	05/24/93
178829	KGS	QTR. NW/NW/SE, SEC. 31, T-9N, R-3W	MCCLAIN	OK	TRIBUTARY OF SOUTH CANADIAN RIVER	06/08/93
178817 F93-2951	KGS	QTR. NW/NW/NE, SEC. 17, T-10N, R-10W	CADDO	OK	MEDICINE CREEK > UNKNOWN CANYON	06/08/93
184985	KGS	QTR. SE/SE, SEC. 33, T-5N, R-6E	PONTOTOC	OK	UNNAMED CREEK	07/07/
	KGS	QTR. SW/NE, SEC. 30, T-25N R-14E	WASHINGTON	OK	CURL CREEK	07/14/93
187284	KGS	QTR. NW, SEC. 30, T-25N, R-13E	WASHINGTON	OK	CANEY RIVER	07/19/93
	KGS	QTR. NE, SEC. 20, T-2S, R-7W	STEPHENS	OK	DRY CREEK BED > UNNAMED CREEK	09/17/93
198823 199536	KGS	QTR. SW, SEC. 21, T-24N, R-10E	OSAGE	OK	FOUR MILE CREEK	09/21/93

SCHEDULE A

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
198898 F93-4259	KGS	QTR. NE/NW, SEC. 13, T-5N, R-5E	SEMINOLE	OK	SALT CREEK > SALT CREEK RESERVOIR	09/22/93
	KGS	SEC. 5, T-1S, R-8W	STEPHENS	OK	UNNAMED CREEK	10/31/93
208055 F94-0564	KGS	QTR. SW, SEC. 6, T-14N, R-6W HWY 81, OKARCHE, 5 MILES E ON COUNTY LINE RD., 3/4 MILES SOUTH	CANADIAN	OK	UNNAMED CREEK > POND (CANADIAN GOOSE KILLED)	11/15/93
208775	KGS	QTR. SW, SEC. 20, T-6S, R-2E	LOVE	OK	UNNAMED CREEK > HICKORY CREEK	11/19/93
209868 F94-0656	KGS	QTR. NE, SEC. 2, T-7N, R-2E	POTTAWATOMIE	OK	UNNAMED CREEK > POSSIBLY TO SALT CREEK	11/26/93
211157	KGS	QTR. NW, SEC. 31, T-5N, R-5E	PONTOTOC	OK	DITCH > UNNAMED CREEK	12/06/93
	KGS	SEC. 31, T-29N, R-10E	OSAGE	OK	UNNAMED POND / CREEK	12/06/93
	KGS	QTR. NW, SEC. 5, T-24N	CREEK	OK	UNNAMED CREEK	12/13/93
212549	KGS	QTR. NE/SW, SEC. 35, T-5N, R-4E	PONTOTOC	OK	UNNAMED CREEK	12/14/93
	KGS	QTR. NW, SEC. 36, T-1S, R-5W	STEPHENS	OK	CREEK / STREAM	12/17/93
214584	KGS	SEC. 24, T-2N, R-8W 2 MILES EAST OF HWY 81 ON HWY IN MARLOW	STEPHENS	OK	HELL CREEK	12/29/93
214787 F94-1134	KGS	QTR. NW, SEC. 2, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK	01/01/94
215545	KGS	SEC. 34, T-24N, R-9E	OSAGE	OK	TWO MILE CREEK	01/06/94
219409	KGS	QTR. NW, SEC. 29, T-26N, R-8E	OSAGE	OK	SOUTH BIRD CREEK	01/29/94
222481 F94-1831	KGS	QTR. NE, SEC. 8, T-5S, R-1E	CARTER	OK	UNNAMED CREEK > HICKORY CREEK	02/19/94

SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
	KGS	QTR. NW, SEC. 9, T-2S, R-2W	CARTER	OK	TRIBUTARY TO BEAR CREEK	02/20/94
224003	KGS	QTR. SE, SEC. 11, T-2S, R-3W	CARTER	OK	UNNAMED CREEK > UNKNOWN	03/01/94
224143	KGS	QTR. SW, SEC. 15, T-5S, R-1W	CARTER	OK	UNNAMED CREEK > WALNUT BAYOU CREEK	03/02/94
230814	KGS	QTR. NW, SEC. 28, T-5N, R-6E	PONTOTOC	OK	UNNAMED CREEK	03/19/94
	KGS	QTR. NE/NW, SEC. 19, T-7N, R-1W	CLEVELAND	OK	UNNAMED CREEK	04/01/94
238014	KGS	QTR. NW, SEC. 30, T-1S, R-3W	CARTER	OK	UNNAMED FARM POND	05/04/94
	KGS	QTR. SE, SEC. 20, T-5N, R-4W	McCLAIN	OK	UNNAMED POND	05/04/94
238225	KGS	WEBB CITY STATION ON HWY 11	OSAGE	OK	DRY CREEK BED	05/05/94
238852	KGS	QTR. NE/NE, SEC. 24, T-5N, R-3W	McCLAIN	OK	UNNAMED CREEK	05/10/94
240445	KGS	QTR. SE, SEC. 2, T-7N, R-2E TRIBBEY STATION	POTTAWATOMIE	OK	COON CREEK	05/21/94
245317	KGS	QTR. SE, SEC. 13, T-16N, R-13E	TULSA	OK	UNNAMED STREAM	06/21/94
259249	KGS	QTR. NE, SEC. 1, T-7S, R-2E	LOVE	OK	UNNAMED TRIBUTARY TO HICKORY CREEK (IN GAME REFUGE)	09/06/94
260855	KGS	QTR. NE/SE, SEC. 4, T-2S, R-3W	CARTER	OK	CADDO CREEK (SPILL OVER 26 MILES) UNKNOWN CREEK > WASHITA RIVER	09/16/00
266339	KGS	SEC. 3, T-4S, R-3W	CARTER	OK	WHISKEY CREEK	10/21/94
267957 F95-0465	KGS	QTR. SW, SEC. 6, T-7S, R-3W 5 MILES NE OF MARIETTA	LOVE	OK	UNNAMED CREEK > HICKORY CREEK	11/01/94
268040 F95-0475	KGS	SEC. 11, T-4N, R-6W	GRADY	OK	UNNAMED CREEK	11/02/94
268612 F95-0526	KGS	SEC. 4, T-1S, R-3W HWY 76	CARTER	OK	WILD HORSE CREEK > WASHITA RIVER	11/07/94

SCHEDULE A

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
270381 F95-0710	KGS	QTR. NW, SEC. 31, T-6S, R-3E	LOVE	OK	TRIBUTARY OF HICKORY CREEK	11/20/94
279685	KGS	SEC. 25, T-14N, R-7E	OSAGE	OK	UNKNOWN WASH > BIG HOMINY CREEK	02/13/95
279987	KGS	QTR. SW, SEC. 30, T-8N, R-1W, NEAR MCGUIRE ROAD IN NOBLE, OK	CLEVELAND	OK	UNNAMED CREEK	02/15/95
280599	KGS	SEC. 18, T-23N, R-8W	OSAGE	OK	DRY CREEK BED	02/20/95
282530	KGS	QTR. NE, SEC. 7, T-4S, R-2W, WILSON JCT	CARTER	OK	WALNUT CREEK	03/08/95
	KGS	7-8 MILES NORTH OF NOCONA	MONTAGUE	TX	WET/DRY CREEK	05/17/90
23701	KR	SUNTIDE ROAD	NUECES	TX	GULF OF MEXICO	05/25/90
	KGS	15 MILES EAST OF GUTHRIE	KING	TX	BUFFALO CREEK	05/31/90
26732	KGS	BARRY CREEK, BETWEEN LYNAS AND CALDWELL	BURLESON	TX	BARRY CREEK	06/13/90
32162	KGS	CB STEWART SURVEY ON FM 1314, 9 MILES SOUTH OF CONROE ON FM 1314	MONTGOMERY	TX	SANDY BRANCH CREEK	07/23/90
	KGS	AT BAIRD, TURN N ON 283, TURN E ON FM 576	CALLAHAN	TX	STOCK POND	10/02/
	KGS	3 MILES SOUTHWEST OF LONGVIEW; SLOUGH ADJACENT TO HAWKINS CREEK, McMURRAY LEASE S OF U.S. 80, N OF GOLF COURSE	GREGG	TX	DRAINAGE DITCH > SLOUGH > STOCK POND > HAWKINS CREEK	12/08/90

SCHEDULE A

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
52667	KR	TULE LAKE WETLANDS, APPROX 2 MILES E OF SUNTIDE ROAD & IMMEDIATELY S OF RAILROAD TRACK	NUECES	TX	CORPUS CHRISTI INNER HARBOR, NUECES- RIO GRANDE COASTAL	12/27/90
	KGS	KOCH GATHERING SYSTEMS BARGE DOCKS INGLSIDE, TX	SAN PATRICIO	TX	CORPUS CHRISTI BY SHIP CHANNEL	12/28/90
	KGS	WITHIN CITY LIMITS OF SHERMAN	GRAYSON	TX	OIL FLOWED INTO A "DRAINAGE WAY"	01/02/91
56394	KGS	FROM HWY 42 N TURN RIGHT ON OLD HWY 80, 4 MILES, TURN LEFT ON WHATLEY (5 MILES E OF WHITE OAK, NORTH OF PAYNE ROAD)	GREGG	TX	STOCK POND	01/24/91
56671	KGS	HAWKINS CREEK AT GEORGE RITCHEY ROAD IN WHITE OAK	GREGG	TX	HAWKINS CREEK (6 MILES N OF SABINE RIVER)	01/26/91
	KGS	6 MILES NE OF CAPPS CORNER	COOKE	TX	MOUNTAIN CREEK, TRINITY	01/30/91
60093	KGS	6 MILES SE OF DIME BOX ON COUNTY ROAD 430	LEE	TX	STOCK POND	02/18/91
63529	KGS	FR 141 (JOHN DOBBINS)	LEE	TX	STOCK POND	03/14/91
	KGS	BLOCK (J.Y. CASSTILLO)	MONTAGUE	TX	STOCK POND	04/01/91
68004	KGS	FM 1314	MONTGOMERY	TX	CRYSTAL CREEK	04/14/91
	KGS	NEAR LEVERETT'S CHAPEL, TURN RIGHT ON DON EVERETT RD., GO TO AMERICAN PLANT RD., TURN RIGHT, 1ST CATTLEGUARD (YELLOW & BLACK) GO .5 MILES	RUSK	TX	TURKEY CREEK	05/14/91

SCHEDULE A

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
	KGS	FROM GUTHRIE TO ASPERMONT, 12 MILES PAST CROTON RANCH CATTLEGUARD; AT 2ND CATTLEGUARD, GO TO COMB. LOCK 35 67 THRU GATE, 8 MILES	KING	TX	CROTON CREEK	05/26/91
	KGS	N OF ASPERMONT, TURN RIGHT AT FLASHING LIGHT, GO 2 MILES, TURN RIGHT AT HOUSE, GO PAST ASPERMONT AIRPORT 1 1/2 MILE, TURN LEFT INTO GATE, GO 1/4 MILES AND TURN RIGHT AT PUMP JACK. FOLLOW ROAD	STONEWALL	TX	CREEK LEADING TO BRAZOS RIVER	06/12/91
	KGS	G.W. THOMPSON	MONTAGUE	TX	MADDOX CREEK	06/14/91
	KGS	M. LOPEZ, SEC. 112, T-16N, R-11E	WEBB	TX	CREEK > STOCK POND	07/06/91
	KGS	WEST OF MORAN ON FM 576, GO 3 MILES WHEN ROAD MAKES S CURVE, TAKE COUNTY ROAD GOING SOUTH, 5 MILES, CROSS CREEK & 2 CATTLEGUARDS; TURN RIGHT AT 2ND CATTLEGUARD, GO THRU GATE, TURN LEFT	CALLAHAN	TX	DRY CREEK BED	07/23/91
	KGS	UNIVERSITY, SEC. 139	CALLAHAN	TX	UNNAMED CREEK	07/23/91
	KGS	BUFFALO BRAZOS & CO.	THROCKMORTON	TX	STOCK POND	07/24/91
	KGS	OFF AVE E IN ALGOA	GALVESTON	TX	DICKINSON BAYOU	07/29/91
82624 85053	KGS	SUNTIDE RD	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	08/06/91

SCHEDULE A

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
83394	KGS	OFF OF AMERICAN PLANT RD MEREDITH MCCABE SURVEY, SOUTH OF KILGORE	RUSK	TX	RABBIT CREEK	08/12/91
85144	KGS	HWY 42 ON THE WEST SIDE, 7 MILES SOUTH OF KILGORE	RUSK	TX	GROUND > RABBIT CREEK	08/23/91
	KGS	5 MILES N OF FORT GRIFFIN ON STANLEY IRWIN'S PROPERTY	THROCKMORTON	TX	PLUM BRANCH CREEK	09/16/91
	KGS	OUT OF GUTHRIE GO TOWARD KNOX CITY, 4 MILES BEFORE YOU GET TO A CAFE -- BATEMAN RANCH, TURN LEFT AT MASTERSON RANCH HEAD	KING	TX	LITTLE WICHITA RIVER	09/26/91
90615	KGS	ON HWY 42	GREGG	TX	SLOUGH	10/01/91
91375	KGS	100 YDS N OF HWY 80, 1 MILE E OF GLADEWATER	GREGG	TX	MOODY CREEK	10/05/91
91195	KGS	7 MILES N OF KILGORE NEAR HWY 42 AND MERRILL'S LAKE ROAD	GREGG	TX	DRAINAGE SLOUGH AREA > SABINE RIVER (CITY WATER SUPPLY)	10/06/91
93529	KGS	8 MILES N OF KILGORE ON HWY 42	GREGG	TX	HAWKINS CREEK	10/23/91
	KGS	CITY OF SHERMAN, EAST SIDE 1 MILE S OF HWY 82 AT CREEK	GRAYSON	TX	UNNAMED CREEK > RED RIVER	10/29/91
	KGS	GO I-20W, TAKE SYLVESTER ROAD CUT-OFF, CROSS OVER, GO WEST ON FEEDER ROAD, GO 1 MILE, GATE ON LEFT	NOLAN	TX	UNKNOWN CREEK	10/31/91
	KGS	7 MILES N OF ST. JO	MONTAGUE	TX	TRIBUTARY OF MOUNTAIN CREEK	11/03/91
	KGS	LAKE GRAHAM	YOUNG	TX	LAKE GRAHAM	11/04/91

SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
95921	KR	SUNTIDE RD	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	11/12/91
96598	KGS	AMOCO WHATLEY LEASE B	GREGG	TX	WASH INTO HAWKINS CREEK	11/17/91
98606	KGS	OFF OF HWY 80, 2 MILES N ON WHITE OAK ROAD, 2 MILES E ON TUTTLE RD	GREGG	TX	HAWKINS CREEK	12/06/91
	KGS	1 BLOCK S OF HWY 82 ON HWY 1417	GRAYSON	TX	UNNAMED CREEK	12/06/91
	KS	FM 517 ON S SIDE FR SAN LEON, MARSHALL WELL, WACKER SEAGULL PRODUCERS	GALVESTON	TX	DITCH > BAYOU (HL&P FEED CANAL)	12/20/91
	KGS	HUBBARD CREEK, 8 MILES N OF MORAN, TX	SHACKLEFORD STEPHENS	TX	HUBBARD CREEK	12/24/91
100979	KGS	NORTH OF WHITE OAK ON WHITE OAK ROAD TO TURTLE ROAD, RIGHT ON WHATLEY ROAD, GO SOUTH, 1ST LEASE ROAD TO LEFT	GREGG	TX	HAWKINS CREEK	12/27/91
101598	KGS	SHELL CAMP RD AND HWY 80, 5 MILES EAST OF WHITE OAK ON HWY 80	GREGG	TX	MOODY CREEK > SABINE RIVER	01/04/92
102386	KR	20 MILES SOUTH OF SAN ANTONIO 1/2 EAST OF STATE HWY 181, 5 MILES NORTH OF FLORESVILLE, TX	BEXAR WILSON	TX	GROUNDWATER CONTAMINATION, DRY WASH > POND	01/10/92
103738	KGS	E ON HWY 80, 3 MILES E OF GLADEWATER	GREGG	TX	MOODY CREEK	01/21/92
106956	KR	CORPUS CHRISTI INNER HARBOR DOCK #9, SUNTIDE ROAD	NUECES	TX	CORPUS CHRISTI INNER HARBOR	02/15/92
107129	KR	CORPUS CHRISTI PORT, OIL DOCK #9	NUECES	TX	CORPUS CHRISTI INNER HARBOR	02/17/92

SCHEDULE A

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NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
108300	KGS	NEAR HW 87, 1.10 MILES W OF NIXON, TEXAS	WILSON	TX		02/26/92
108586 F92-1711	KGS	8 MILES NORTH OF FREER ON HWY 16, TONAS RANCH	DUVAL	TX	SAN YGNACIO CREEK	02/28/92
109055	KGS	HWY 80 AT MOODY CREEK 2 MILES E OF GLADEWATER	GREGG	TX	MOODY CREEK	03/03/92
110034	KR	CORPUS CHRISTI PORT, OIL DOCK #8, SUNTIDE RD	NUECES	TX	CORPUS CHRISTI PORT	03/10/92
110981	KGS	TETTLE RD	GREGG	TX	UNNAMED CREEK	03/18/92
113658	UGP	5 MILES S OF CITY OF PANOLA	PANOLA	TX	STAGNANT POND BACKWATER OF SOCAGEE CREEK	04/09/92
116279	KGS	EAST TEXAS FIELD, MOODY CREEK AT HWY 80	GREGG	TX	MOODY CREEK	04/30/92
	KGS	1 MILE NORTH OF NUECES RIVER ON WEST SIDE OF I-37; ENTER MAIN WELDER RANCH GATE, GO TO 1ST TANK BATTERY	SAN PATRICIO	TX	GROUNDWATER CONTAMINATION, NEAR HONDO CREEK AND NUECES RIVER	06/01/92
	KGS	CARROLL CREEK FROM UPSTREAM OF HWY 199 TO BEYOND HWY 380	JACK WISE	TX	CARROLL CREEK > TRINITY RIVER	06/02
	KGS	SAXON ROAD, NEAR LEVIRITT'S CHAPEL, SE OF KILGORE	RUSK	TX	TRIBUTARY TO RABBIT CREEK	06/15/92
122364	KGS	1.9 MILES E OF U.S. 123 ONTO CR 233, THEN GO 2.1 MILES TO FABIAN VEILA LEASE	KARNES	TX	MULTIFEST CREEK > SAN ANTONIO RIVER	06/17/92

SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
128059 F92-3444	KGS	GLADEWATER EAST - 2 MILES EAST ON HWY 80 AND 2 MILES SOUTH ON LOCKER - PLANT RD	GREGG	TX	CREEK > SABINE RIVER	07/21/92
128493 F92-3572	KGS	25 MILES NE OF BRECKENRIDGE	YOUNG	TX	CREEK BED, CLEAR FORK OF BRAZOS RIVER	07/23/92
137080	KR	KOCH REFINERY DOCK #10	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	09/17/92
139319	KGS	HWY 31 AND 135 JUNCTION	GREGG	TX	DRY CREEK BED / DRY CREEK TRIBUTARY OF LITTLE RABBIT CREEK	10/05/92
148470 148827	KGS	BRADLEY RANCH, 18 MILES S/SW OF KNOX CITY	STONEWALL	TX	DITCH AND CREEK DRAWER > NORTH CROTON CREEK > WELLINGTON CREEK	12/10/92
149052	KGS	OFF WATLEY RD	GREGG	TX	UNNAMED CREEK AND POND	12/14/92
150961	KGS	H L WILKERSON SURVEY A1113, 3/4 MILES SOUTH OF BULCHER AT MOUNTAIN CREEK	MONTAGUE	TX	BRANCH OF MOUNTAIN CREEK	12/29/92
155894	KR	498 POPGUN DRIVE, SAN ANTONIO	BEXAR	TX	GROUNDWATER CONTAMINATION	01/31/93
156859	KGS	WHITE OAK RD NEAR HARLEY RDGE RD	GREGG	TX	UNNAMED CREEK > HAWKINS CREEK	02/05/93
156918 F93-1404	KGS	4 MILES W OF LYON ON FM 60, RIGHT ON CR 405, GO TO END OF ROAD	BURLESON	TX	HICKORY CREEK, TWO SEPARATE UNNAMED CREEKS, A STOCK POND AND A POND IN FRONT OF A RESIDENCE	02/06/93
	KGS	S ON 281 FROM PREMONT, 1/2 MILE LEFT ON CR 418A, GO 3 MILES TO HOUSE WITH WINDMILL ON LEFT	BROOKS	TX		03/11/93
161939	KGS	HWY 1069, INGLESIDE DOCK	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	03/12/93

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
184723	KGS	2 MILES NE OF WHITE OAK, 1/4 MILE SOUTH OF GEORGE RITCHEY ROAD	GREGG	TX	HAWKINS CREEK	07/06/93
210209	KGS	WEST SIDE OF HWY 42 SOUTH OF KILGORE ON HWY 42	RUSK	TX	UNNAMED CREEK	11/29/93
	KGS	PAINE RANCH	MONTAGUE	TX	SALT CREEK	12/29/
223156	KGS	KILGORE, HWY 31, 3/4 MILES EAST OF HWY 135	GREGG	TX	RABBIT CREEK	02/23/94
230173	KR	SUNTIDE ROAD, OIL DOCK #9	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	03/16/94
237766	KGS	57 BLOCK D ETRC SURVEY, 5 MILES NW OF ALBANY NEAR FM 1084	SHACKELFORD	TX	COOK CREEK	05/03/94
241271	KGS	FM 1073, 4 MILES FROM ALBANY	SHACKELFORD	TX	UNNAMED CREEK > HUBBARD CREEK	05/27/94
241439	KGS	N OF LONGVIEW ON HWY 1845 HAWKINS CREEK	GREGG	TX	HAWKINS CREEK	05/28/94
241995	KGS	5 MILES S OF CONROE ON 3083 FARM ROAD	MONTGOMERY	TX	CRYSTAL CREEK	06/02/94
242164	KGS	THOMPSON ROAD	GREGG	TX	SMALL UNNAMED CREEK > HAWKINS CREEK	06/03/00
242966	KGS	5 MILES EAST OF MURRAY, TAKE FIRST GATE ON RIGHT AFTER RURAL WATER TANKS, JACKSON RANCH	YOUNG	TX	TRIBUTARY TO FISH CREEK	06/06/
251734	KGS	RANSOME HOUSE A-244 DIESEL	MONTGOMERY	TX	CRYSTAL CREEK	07/26/94
254845	KGS	APPROX 5 MILES S OF HWY 44	NUECES	TX		08/11/94
255040	KGS	EAST TEXAS FIELD, HWY 1845	GREGG	TX	HAWKINS CREEK > SABINE RIVER	08/12/94

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
260980	KGS	UNNAMED CREEK LEADS TO UNNAMED POND	COOKE	TX	UNNAMED CREEK / UNNAMED POND	09/16/94
263545	KGS	2 MILES NORTH OF MORAN UNIVERSITY LAND SURVEY	SHACKELFORD	TX	CREEK BED	10/02/94
263973	KR	SUNTIDE ROAD	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	10/05/94
264456 264419	KGS	KOCH REFINERY 3 MILES UP DRAINAGE DITCH FROM SHORE OF NUECES BAY WEST OF PORTLAND, CR 72	SAN PATRICIO	TX	BROKEN 10" PIPELINE; 400 BBLs. OF NIGERIAN CRUDE WAS DISCHARGED INTO THE NUECES AND CORPUS CHRISTI BAYS	10/08/94
265735	KGS	136 YARDS SOUTH OF HWY 359 QUARTER MILE EAST OF FM 649	WEBB	TX	DRY CREEK BED	10/17/94
F95-0659	KR	SHAW ROAD OR MISSION RIVER OAKS ROAD	REFUGIO	TX		11/12/94
270797 F95-0757	KGS	FM 180	LEE	TX	SMALL CREEK	11/23/94
272157 F95-0920 272193 F95-0928	KGS	NEAR THE INTERSECTION OF F.M. 141 & C.R. 430, SE OF DIME BOX	LEE	TX	UNNAMED CREEK > YEGUA CREEK > LAKE SOMERVILLE	12/06/94
F95-0923	KGS	4 MILES NW OF SHERMAN	GRAYSON	TX	UNNAMED CREEK	12/06/94
273760 F95-1125	KGS	CONROE FIELD CONROE, TX	MONTGOMERY	TX	CRYSTAL CREEK	12/19/94
274992 F95-1272	KGS	SECTION 5 OF COMANCHE INDIAN RESERVE, THROCKMORTON, TX	THROCKMORTON	TX	UNNAMED CREEK > BRAZOS RIVER	12/31/94

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SCHEDULE A

NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
276128 F95-1406	KGS	4 MILES SOUTH OF WHITE OAK, TX, OFF HWY 42	GREGG	TX	UNNAMED CREEK	01/12/95
276902 F95-1504	KGS	1/2 MILE WEST OF FM 3083 ON TEXACO ROAD, 5 MILES SE OF CONROE, TX	MONTGOMERY	TX	CRYSTAL CREEK	01/19/95
277052 F95-1520	KGS	HWY 180, 3 MILES EAST OF GLADEWATER, TX	GREGG	TX	DRAINAGE DITCH > MOODY CREEK	01/20/95
277940	KGS	COUNTY ROAD 169	FAYETTE	TX	SPRING CREEK	01/29/95
278236	KGS	15 MILES NORTH OF MUENSTER	COOKE	TX	CREEK > MOUNTAIN CREEK	01/31/95
279292	KGS	SECT. 802 PREMIUM SURVEY	THROCKMORTON	TX	UNNAMED CREEK	02/09/95
283073	KGS	5 MILES SOUTH OF FALLS CITY, TX	KARNES	TX	CREEK BED	03/13/95
286138	KGS	3 MILES EAST OF TILDEN	MCMULLEN	TX	SLOUGH / POND / LA JARITA CREEK	04/07/95

Dated: April 17, 1995

#35
UNITED STATES COURTS
SOUTHERN DISTRICT OF TEXAS
FILED

UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

APR 24 1996

MICHAEL N. MILBY, Clerk of Court

UNITED STATES OF AMERICA,)
)
Plaintiff,)
v.) Civil Action No. H 95-1118
)
KOCH INDUSTRIES, INC., et al.)
)
Defendants.)

PLAINTIFF'S REVISED MOTION TO AMEND SCHEDULE "A"
TO THE ORIGINAL COMPLAINT

Plaintiff United States of America moves this Court pursuant to Rule 15(a), F.R.Civ.P., to amend Schedule "A" attached to the Plaintiff's Original Complaint, and would show the Court:

1. Plaintiff's Original Complaint was filed April 17, 1995, and included as an exhibit pursuant to Rule 10(c), F.R.Civ.P., Schedule "A". Schedule "A" lists the date, National Response Center Number (if reported), location (including county and state), and affected waterway of each alleged discharge by defendants of oil or hazardous substances into the waterways of the United States of America, as alleged in paragraph 33 of the Original Complaint.

2. On April 5, 1996, this Court ordered plaintiff to move to dismiss claims or to amend its pleadings to reflect that certain discharges had been deleted as a result of further investigation by plaintiff. Consequently, plaintiff has eliminated from its case nineteen discharges and has amended Schedule "A" to reflect these changes. Initially, the United States intended to add additional discharges to the Schedule, but has not included additional

discharges in the attached amended Schedule. In addition, any errors or omissions on the Schedule have been corrected.

3. Eliminations and modifications to the Schedule, and the reasons therefore, are discussed at length in plaintiff's April 15, 1996 letter to Koch (also sent to the Court as requested), and are included in plaintiff's Second Amended Schedule "A," attached to this motion as Exhibit A.

Plaintiff respectfully moves this Court to amend the Schedule "A" attached to the Complaint under Rule 10(c), F.R.Civ.P. by substituting plaintiff's Second Amended Schedule "A."

Respectfully submitted,

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Kansas City, KS 66101

CERTIFICATE OF SERVICE

I hereby certify that copies of Plaintiff United States' revised motion to amend schedule "A" to the original complaint, and Order were mailed by first class mail, postage prepaid to the following counsel of record on April 24, 1996:

Porter & Hedges
Daniel K. Hedges
700 Louisiana
35th Floor
Houston, TX 77002

Kelley D. Sears
Koch Industries, Inc.
4111 E. 37th Street North
Wichita, KS 67220


GORDON M. SPEIGHTS YOUNG

UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

UNITED STATES OF AMERICA,)	
)	
Plaintiff,)	
v.)	Civil Action No. H 95-1118
)	
KOCH INDUSTRIES, INC., et al.)	
)	
Defendants.)	

ORDER GRANTING PLAINTIFF'S REVISED MOTION TO AMEND SCHEDULE "A"
TO THE ORIGINAL COMPLAINT

Plaintiff United States of America's Revised Motion to Amend Schedule "A" attached to the Plaintiff's Original Complaint, pursuant to Rule 15 (a), F.R.Civ.P., with leave of the Court, is granted;

It is therefore Ordered that Schedule "A" to the Original Complaint is amended by the substitution of the Revised Amended Schedule "A."

DONE April ____, 1996, at Houston, Texas.

VANESSA GILMORE
United States District Judge

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 4	130388	KGS	CITRONELLE, ALABAMA	MOBILE	AL	LITTLE CREEK	08/04/92
K 5	249208	KGS	RUSSELL ROAD, CITRONELLE, ALABAMA, SOUTH OF MARKS LANE	MOBILE	AL	PUPPY CREEK / SPRING	07/14/94
K 7	264809	KM	4915 CHELSEA STREET KANSAS CITY, MO	JACKSON	MO	LITTLE BLUE RIVER	10/11/94
K 8		KGS	QTR. SE, SEC. 26, T-14S, R-27W	GOVE	KS	UNNAMED CREEK > SMOKY CREEK POND	02/05/91
K 9		KGS	QTR. SE, SEC. 4, T-14S, R-15W	RUSSELL	KS	UNNAMED CREEK	03/18/91
K 10	110633	KS	QTR. NE, SEC. 28, T-21S, R-11W	STAFFORD	KS	BIG SALT MARSH (WETLAND) IN QUIVIRA NATIONAL WILDLIFE REFUGE > RATTLESNAKE CREEK > ARKANSAS RIVER	03/13/92
K 11		KGS	QTR. SW, SEC. 1, T-12S, R-18W	ELLIS	KS	UNNAMED CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	10/12/92
K 13		KGS	QTR. NW, SEC. 33, T-11S, R-19W	ELLIS	KS	UNNAMED INTERMITTENT STREAM	02/03/93
K 14		KGS	QTR. NW, SEC. 23, T-10S, R-15W	OSBORNE	KS	UNNAMED POND > PARADISE CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	03/06
K 15		KGS	QTR. SE, SEC. 18, T-20S, R-15W	BARTON	KS	UNNAMED POND > UNNAMED CREEK > DRY WALNUT CREEK > ARKANSAS RIVER	03/29/93
K 16		KGS	QTR. NW, SEC. 19, T-12S, R-15W	RUSSELL	KS	UNNAMED CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	04/19/93

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 17		KGS	QTR. SE, SEC. 31, T-11S, R-20W	ELLIS	KS	SPRING CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	05/22/93
K 18		KGS	QTR. SE, SEC. 8, T-15S, R-12W	RUSSELL	KS	BAR DITCH > UNNAMED CREEK > SMOKY HILL RIVER > KANSAS RIVER	05/30/93
K 19		KGS	QTR. NW, SEC. 10, T-10S, R-19W	ROOKS	KS	BAR DITCH > DEPRESSION > SAND CREEK SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER (A.K.A. KAW RIVER)	06/02/93
K 20		KGS	QTR. NW, SEC. 16, T-10S, R-15W	OSBORNE	KS	BAR DITCH > PARADISE CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	07/13/93
K 21		KGS	QTR. SE, SEC. 18, T-20S, R-15W	BARTON	KS	UNNAMED POND > UNNAMED CREEK > DRY WALNUT CREEK > WALNUT CREEK > ARKANSAS RIVER	07/23/93
K 22		KGS	QTR. SE, SEC. 31, T-11S, R-20W	ELLIS	KS	SPRING CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	08/27/93
K 23		KGS	QTR. NW, SEC. 15, T-15S, R-18W	ELLIS	KS	TWO UNNAMED PONDS > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	09/01/93
K 24		KGS	QTR. NE, SEC. 15, T-11S, R-19W	ELLIS	KS	UNNAMED INTERMITTENT STREAM > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	09/10/93
K 25		KGS	QTR. NW, SEC. 31, T-11S, R-12W	ELLIS	KS	POND	09/15/93
K 26		KGS	QTR. NE, SEC. 36, T-10S, R-19W	ROOKS	KS	SAND CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	09/25/93

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 27		KGS	QTR. SE, SEC. 6, T-17S, R-19W	RUSH	KS	UNNAMED DRAW > BIG TIMBER CREEK > SMOKY HILL RIVER > KANSAS RIVER	10/04/93
K 28		KGS	QTR. SW, SEC. 27, T-16S, R-10W	ELLSWORTH	KS	PLUM CREEK > COW CREEK > ARKANSAS RIVER	11/18/93
K 29	212092	KGS	QTR. SW, SEC. 27, T-16S, R-10W	ELLSWORTH	KS	PLUM CREEK > COW CREEK > ARKANSAS RIVER	12/10
K 30	212808	KGS	QTR. SE, SEC. 5, T-12S, R-17W	ELLIS	KS	UNNAMED CREEK > SALINE RIVER > SMOKY HILL RIVER > KANSAS RIVER	12/15/93
K 31	216801	KGS	18 MILES NE OF HAYS SEC. 1, T-12S, R-18W	ELLIS	KS	UNNAMED CREEK	01/14/94
K 32	234684	KGS	SEC. 12, T-11S, R-18	ELLIS	KS	UNNAMED CREEK	04/13/94
K 33	241964	CP	QTR. NE/NE/NE, SEC. 8, T-26, R-2E	SEDGWICK	KS	NORMALLY DRY CREEK	06/02/94
K 34	247493	KGS	SEC. 15, T-6S, R-22W	GRAHAM	KS	UNNAMED TRIBUTARY TO BOW CREEK	07/04/94
K 35	263945	KGS	SEC. 27, T-16, R-10W	ELLSWORTH	KS	DRY CREEK	10/05
K 36	278002	KGS	SEC. 7, T-12S, R-15W, 14 MILES NW OF GORHAM	RUSSELL	KS	WORTH CREEK	01/29/95
K 37	281654	KGS	SEC. 4, T-14S, R-15W, 1.5 MILES SE OF GORHAM, KS	RUSSELL	KS	STREAM	03/01/95
K 38	40155	KGS		ST. JAMES	LA	MISSISSIPPI RIVER	09/20/90

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 41	170963	KGS	BAYOU BLUE OIL FIELD 15 MILES S OF GROSSE TETE	IBERVILLE	LA	MARSH AREA > UPPER GRAND RIVER, WETLAND NEAR BAYOU RICHARD	05/02/93
K 43	269964 F95-0667	KGS	4 MILES EAST OF 79 ON ALTERNATE 2, EAST HAYNESVILLE FIELD	CLAIBORNE	LA	REEDER CREEK	11/16/94
K 44	18146	KGS	QTR. SE, SEC. 32, R-5N, R-5E	PONTOTOC	OK	UNNAMED POND	04/20/90
K 45	19391	KGS	QTR. SW, SEC. 19, T-1S, R-2W TATUM STATION	CARTER	OK	STREAM	04/27/90
K 46	19433	KGS	QTR. SE, SEC. 10, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK TRIBUTARY > MUD CREEK	04/27/90
K 47		KGS	QTR. SE, SEC. 6, T-2S, R-4W	STEPHENS	OK	UNNAMED CREEK	04/30/90
K 48	20378	KGS	QTR. SE, SEC. 26, T-5N, R-4E	PONTOTOC	OK	UNNAMED CREEK > SOUTH CANADIAN RIVER	05/03/90
K 49	20532	KGS	QTR. NE, SEC. 2, T-9N, R-4E	POTTAWATOMIE	OK	UNNAMED CREEK > NEIGHBORS STOCK POND	05/04/90
K 50	20634	KGS	QTR. SW, SEC. 4, T-1S, R-3W	CARTER	OK	SANDY BEAR > WILD HORSE CREEK > WARHITA RIVER > TEXOMAH	05/05/90
K 51	20680	KGS	7 MILES DOWNSTREAM OF DENISON DAM ON RED RIVER	BRYAN	OK	RED RIVER	05/05/90
K 52	21240	KGS	QTR. SE, SEC. 3, T-2N, R-8W	STEPHENS	OK	UNNAMED STREAM > BEAVER CREEK	05/09/90
K 53	21184	KGS	QTR. NE, SEC. 21, T-6N, R-6E	SEMINOLE	OK	UNNAMED CREEK	05/09/90

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FIRST AMENDED SCHEDULE A

SPIII#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 54	21501	BP	QTR. NE, SEC. 22, T-24N, R-8E	OSAGE	OK	UNNAMED CREEK > HOMINY CREEK	05/10/90
K 55	23854	KGS	SEC. 35, T-5N, R-4E	PONTOTOC	OK	UNNAMED CREEK	05/25/90
K 56	24392	BP	QTR. NW, SEC. 35, T-27N, R-15E	NOWATA	OK	CALIFORNIA CREEK	05/29/90
K 57	24377	BP	QTR. SW, SEC. 2, T-17N, R-12E	TULSA	OK	UNNAMED CREEK	05/29/90
K 58	24650	BP	QTR. NW, SEC. 18, T-27N, R-15E	NOWATA	OK	UNNAMED STREAM	05/30/90
K 59		KGS	QTR. SE, SEC. 12, T-1S, R-4W	STEPHENS	OK	SWAMPY AREA	05/30/90
K 60	25363	BP	QTR. NE/SW, SEC. 33, T-21N, R-12E HWY 75	OSAGE	OK	CREEK > UNNAMED RIVER	06/04/90
K 61	26995	KGS	QTR. NE, SEC. 29, T-6S, R-2E	LOVE	OK	CREEK > LAKE	06/15/90
K 62	27000	KGS	SEC. 33, T-5N, R-5E	PONTOTOC	OK	BUCKHORN CREEK	06/15/90
K 63	28205	KGS	QTR. SW/NW, SEC. 8, T-1N, R-3W	GARVIN	OK	STOCK POND	06/23/90
K 64	28735	KGS	QTR. NE, SEC. 13, T-8N, R-6E	SEMINOLE	OK	UNNAMED CREEK	06/28/90
K 65		KGS	QTR. NW, SEC. 3, T-5N, R-4E	PONTOTOC	OK	SMALL UNNAMED STREAM	07/23/90

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 66	32347	KGS	QTR. NE, SEC. 36, T-5N, R-4E	PONTOTOC	OK	GROUND > 2 SMALL PONDS	07/24/90
K 67		BP	QTR. NW, SEC. 25, T-23N, R-7E	OSAGE	OK	SMALL CREEK	09/24/90
K 68	41047	KGS	QTR. SE, SEC. 30, T-5N, R-7E	PONTOTOC	OK	UNNAMED CREEK	09/25/90
K 69		KGS	QTR. NW, SEC. 2, T-2S, R-5W	STEPHENS	OK	TRIBUTARY, UNNAMED CREEK	11/05/90
K 70		BP	QTR. NE, SEC. 3, T-24N, R-11E	OSAGE	OK	DOG THRASHER CREEK	11/12/90
K 71		KGS	QTR. NE, SEC. 26, T-5S, R-1E	CARTER	OK	HICKORY CREEK	12/26/90
K 72		KGS	QTR. SE, SEC. 27, T-1S, R-5W	STEPHENS	OK	UNNAMED CREEK	12/28/90
K 73	53188	KGS	SEC. 32, T-1S, R-6W	STEPHENS	OK	MUD CREEK	01/01/91
K 74	53333	BP	QTR. SE, SEC. 4, T-24N, R-11E	OSAGE	OK	DOG THRASHER CREEK	01/02/91
K 75		KGS	T-4S, R-3W	CARTER	OK	WALNUT CREEK / SWAMPY AREA	01/07/91
K 76	54518	BP	QTR. NW, SEC. 8, T-25N, R-6E	OSAGE	OK	UNNAMED CREEK	01/10/91
K 77	56446	KGS	QTR. NE, SEC. 30, T-5N, R-5E (QTR. NW, SEC. 35) HWY 3	PONTOTOC	OK	UNNAMED CREEK LEADING TO SOUTH CANADIAN RIVER	01/24/91

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 78	58308	BP	QTR. SW, SEC. 5, T-27N, R-8E	OSAGE	OK	UNNAMED CREEK	02/05/91
K 79	59349	KGS	QTR. SW, SEC. 1, T-15N, R-3E	LINCOLN	OK	UNNAMED CREEK	02/13/91
K 80	60642	BP	QTR. NE, SEC. 32, T-23N, R-11E	OSAGE	OK	DITCH > UNNAMED CREEK > HOMINY CREEK	02/20/91
K 81		BP	QTR. SW, SEC. 3, T-20N, R-8E	PAWNEE	OK	UNNAMED CREEK	02/26/91
K 82		KGS	QTR. NW, SEC. 21, T-3N, R-5W	GRADY	OK	TRIBUTARY OF RUSH CREEK	02/27/91
K 83		KGS	QTR. SW, SEC. 29, T-1S, R-2W	CARTER	OK	UNNAMED CREEK	03/11/91
K 84	67710	KGS	SEC. 20, 21, T-3N, R-5W EATS ON 29, 1/2 MILE FROM COX CITY, THEN SOUTH	GRADY	OK	RUSH CREEK	04/12/91
K 85		KGS	QTR. NW, SEC. 1, T-2S, R-4W	STEPHENS	OK	UNNAMED CREEK	04/29/91
K 86		KGS	QTR. NW, SEC. 8, T-3N, R-5W	GRADY	OK	POND / CREEK / "SOIL LAKE"	05/06
K 87	72628	KGS	SEC. 7, T-22N, R-8E	OSAGE	OK	UNNAMED CREEK > KEYSTONE LAKE	05/19/91
K 88	74569	KGS	QTR. SW, SEC. 31, T-17N, R-3E	LINCOLN	OK	UNNAMED CREEK	06/05/91
K 89		KGS	QTR. SW, SEC. 16, T-2S, R-2W	CARTER	OK	STREAM / CREEK	06/10/91

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 90	75277	KGS	QTR. NE/SE, SEC. 30, T-25N, R-11E	OSAGE	OK	UNNAMED STREAM	06/11/91
K 91	75573	KGS	QTR. NW, SEC. 21, T-25N, R-9E	OSAGE	OK	UNNAMED STREAM	06/12/91
K 92		KGS	QTR. SW, SEC. 15, T-28N, R-7E	OSAGE	OK	CREEK	06/26/91
K 93	79168	KGS	QTR. NE, SEC. 27, T-21N, R-6W SOUTH EDGE OF WYKOMIS OFF COUNTRY RD	GARFIELD	OK	UNNAMED CREEK	07/11/91
K 94	81290	KGS	QTR. SE, SEC. 7, T-1S, R-3W	CARTER	OK	UNNAMED TRIBUTARY TO WILD HORSE CREEK	07/28/91
K 95	88655 85556	KGS	QTR. SE/SW, SEC. 33, T-24N, R-8E	OSAGE	OK	UNNAMED CREEK, TRIBUTARY TO HOMINY CREEK	08/26/91
K 96	86380	KGS	QTR. SE, SEC. 7, T-6N, R-5E	HUGHES	OK	SMALL CREEK	08/30/91
K 97	88393	KGS	QTR. NW, SEC. 2, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK	09/15/91
K 98	89021	KGS	QTR. SE, SEC. 19, T-4S, R-5W	CARTER	OK	UNNAMED CREEK	09/19
K 99	90163	KGS	QTR. NW, SEC. 19, T-7N, R-2W	CLEVELAND	OK	SMALL UNNAMED STREAM	09/28/91
K 100		KGS	QTR. SE, SEC. 10, T-1S, R-4W QTR. NE, SEC. 27, T-1N, R-5W	STEPHENS	OK	DRY CREEK	09/29/91
K 101		KGS	QTR. NE, SEC. 27, T-3N, R-5W	STEPHENS	OK	SMALL UNNAMED CREEK	09/30/91

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 102	92168	KGS		OSAGE	OK	CLEAR CREEK	10/14/91
K 103	92430	KGS	QTR. SW, SEC. 26, T-5N, R-4W	MCCLAIN	OK	UNNAMED CONSERVATION LAKE USED FOR FLOOD CONTROL	10/16/91
K 104	93350	KGS	SEC. 21, T-5N, R-5E	PONTOTOC	OK	TRIBUTARY > BUCKHORN CREEK	10/22/91
K 105	94493	KGS	QTR. NE, SEC. 33, T-1S, R-5W	STEPHENS	OK	SMALL UNNAMED CREEK	10/30/91
K 106	94603	KGS	QTR. SE/NW, SEC. 31, T-4S, R-10E	ATOKA	OK	UNNAMED CREEK > BOGGY CREEK	10/31/91
K 107	95401 F92-0407	KGS	QTR. SW/SW, SEC. 14, T-24N, R-10E	OSAGE	OK	UNNAMED CREEK	11/06/91
K 109	98169	KGS	QTR. SE, SEC. 19, T-21N, R-9E	OSAGE	OK	SMALL CREEK	12/03/91
K 110	98643	KGS	QTR. SW, SEC. 29, T-1S, R-2W	CARTER	OK	UNNAMED CREEK AND SOIL	12/06/91
K 111		KGS	QTR. NE, SEC. 20, T-2S, R-7W	STEPHENS	OK	UNNAMED CREEK	12/17/91
K 112	100328	KGS	QTR. SE, SEC. 33, T-6N, R-6E	SEMINOLE	OK	JUMPER CREEK	12/19/91
K 113	100322	KGS	SEC. 14, T-8S, R-8E	BRYAN	OK	UNNAMED CREEK	12/19/91
K 114	100532	KGS	QTR. SW, SEC. 17, T-3N, R-5W	GRADY	OK	RUSH CREEK	12/20/91

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 115	100509 100714	KGS	QTR. NE, SEC. 16, T-24N, R-7E QTR. NW, SEC. 29, T-24N, R-8E	OSAGE	OK	WET WEATHER CREEK / HOMINY CREEK	12/20/91
K 116	100834	KGS	SEC. 18, T-6N, R-8E	SEMINOLE	OK	CREEK > 3 1/4 MILE DOWN SMALL CREEK	12/25/91
K 117	100994	KGS	QTR. SE, SEC. 13, T-22N, R-11E	OSAGE	OK	QUAPAW CREEK	12/27/91
K 118	101280	KGS	NW QUARTER OF SECTION 24	STEPHENS	OK	UNNAMED CREEK	12/31/91
K 119	101409	KGS	QTR. SE, SEC. 16, T-25N, R-8E 15 MILES NW PAWHUSKA	OSAGE	OK	UNNAMED CREEK LEADING TO CLEAR CREEK	01/02/92
K 120	101750	KGS	QTR. NE, SEC. 36, T-23N, R-7E	OSAGE	OK	UNNAMED CREEK	01/06/92
K 121	103507	KGS	QTR. NE, SEC. 8, T-22N, R-8E CENTER OF THE S 1/2, SEC. 25, T-24N, R-7E	OSAGE	OK	WET/DRY CREEK BED	01/17/92
K 122	103508	KGS	QTR. NW, SEC. 5, T-25N, R-11E	OSAGE	OK	DRAINAGE DITCH > STREAM	01/18/92
K 123	103690	KGS	SEC. 24, T-25N, R-11E	OSAGE	OK	UNNAMED CREEK	01/20
K 124	104084	KGS	QTR. NE, SEC. 18, T-5S, T-1E	CARTER	OK	UNNAMED CREEK	01/22/92
K 125	104423	KGS	SEC. 24, T-21N, R-15W 25 MILES W OF FAIRVIEW	MAJOR	OK	UNNAMED CREEK	01/24/92
K 126		KGS	QTR. NE/NE, SEC. 12, T-3N, R-3W	GARVIN	OK	STREAM AND SWAMPY AREA / LOW-LYING AREA / UNNAMED TRIBUTARY > RUSH CREEK	02/01/92

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 127	107608	KGS	QTR. SW, SEC. 24, T-5S, R-6W	MARSHALL	OK	SMALL POND	02/20/92
K 128	107950	KGS	QTR. SW, SEC. 35, T-5S, R-8E	BRYAN	OK	UNNAMED CREEK	02/24/92
K 129	108189	KGS	SEC. 11, T-6S, R-9E	BRYAN	OK	BLUE RIVER	02/25/92
K 130	121109	KGS	QTR. NW, SEC. 29, T-1S, R-5W	STEPHENS	OK	STOCK POND	06/09/92
K 131	122563	KGS	QTR. NW, SEC. 24, T-24N, R-16E	ROGERS	OK	UNKNOWN CREEK	06/18/92
K 132	122836	KGS	QTR. NW, SEC. 22, T-17N, R-4E	LINCOLN	OK	SMALL UNNAMED CREEK	06/20/92
K 133	122788	KGS	SEC. 21, T-8N, R-3W	CLEVELAND	OK	UNNAMED POND	06/20/92
K 134	123186	KGS	SEC. 14, T-1S, R-4W	STEPHENS	OK	UNNAMED CREEK TRIBUTARY > WILD HORSE CREEK	06/23/92
K 135	123468	KGS	SEC. 29, T-24N, R-12E	OSAGE	OK	UNNAMED TRIBUTARY > CANDY CREEK	06/24/92
K 136	123526 F92-3144	KGS	QTR. SW, SEC. 27, T-1S, R-3W, HWY 76	CARTER	OK	UNNAMED CREEK > WILD HORSE CREEK	06/25/92
K 137	126596	KGS	QTR. SW/SW, SEC. 19, T-14N, R-2E	LINCOLN	OK	SOIL AND UNNAMED CREEK	07/14/92
K 138	127445	KGS	QTR. SE, SEC. 20, T-6N, R-6E	SEMINOLE	OK	UNNAMED CREEK	07/18/92

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 139	130827 F92-3674	KGS	QTR. NW, SEC. 29, T-24N, R-8E	OSAGE	OK	NATURAL STREAM > POND > HOMINY CREEK	08/07/92
K 140	132975	KGS	SEC. 3, T-7N, R-3E	POTTAWATOMIE	OK	FARM POND	08/21/92
K 141	132965	KGS	QTR. NE, SEC. 7, T-2S, R-2W	CARTER	OK	RUSSELL PETTY BRANCH CREEK	08/21/92
K 142	136422	KGS	QTR. SW, SEC. 26, R-5E, T-7S	MARSHALL	OK	SANDY CREEK > LAKE TEXHOMA	09/12/92
K 143	142755	KGS	QTR. SW, SEC. 33, T-20N, R-8E (QTR. SE, SEC. 32)	PAWNEE	OK	HORSE CREEK	10/30/92
K 144		KGS	QTR. SW, SEC. 36, T-1S, R-5W	STEPHENS	OK	CREEK	11/02/92
K 145	144442	KGS	QTR. SW, SEC. 34, T-19N, R-4E STATE HWY 99 BRIDGE	PAYNE	OK	UNNAMED CREEK > CIMMARON RIVER	11/11/92
K 146		KGS	QTR. SW, SEC. 1, T-1S, R-4W	STEPHENS	OK	DRY CREEK	11/30/92
K 147	149130 148963	KGS	QTR. NW, SEC. 15, T-16N, R-5E 1.10 MILES S OF AVERY	LINCOLN	OK	POND AND UNNAMED CREEK	12/13/92
K 148		KGS	QTR. SW/SE, SEC. 17, T-21N, R-8E	PAWNEE	OK	TRIBUTARY	12/28/92
K 149	151016	KGS	QTR. NW, SEC. 11, T-25N, R-9E	OSAGE	OK	UNNAMED CREEK	12/30/92
K 150	F93-0939	KGS	SEC. 13, T-21N, R-12E	TULSA	OK	TRIBUTARY OF BIRD CREEK	12/30/92

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 151	152339	KGS	QTR. NE, SEC. 13, T-21N, R-12E	TULSA	OK	STREAM	01/08/93
K 152	154217	KGS	QTR. NE, SEC. 28, T-5N, R-4W	MCCLAIN	OK	UNNAMED CREEK > LINDSAY LAKE	01/20/93
K 153		KGS	QTR. SW, SEC. 6, T-4N, R-7W	GRADY	OK	POND	01/27/93
K 154	156537	KGS	QTR. NW, SEC. 20, T-22N, R-9E 3 MILES SE OF HOMINY	OSAGE	OK	UNNAMED STREAM	02/04/93
K 155	157228	KGS	QTR. NW, SEC. 13, T-6N, R-5E	POTTAWATOMIE SEMINOLE	OK	UNNAMED CREEK NEAR BEAVER DAM	02/09/93
K 156	157454 F93-1456	KGS	QTR. SE, SEC. 31, T-1N, R-9W	STEPHENS	OK	STAGE STAND CREEK	02/10/93
K 157	157878	KGS	SEC. 29, T-5S, R-7E	MARSHALL	OK	UNNAMED CREEK	02/12/93
K 158	158885	KGS	QTR. SW, SEC. 18, T-22N, R-11E	OSAGE	OK	STOCK POND	02/19/93
K 159	160587	KGS	QTR. SW, SEC. 32, T-2S, R-2W	STEPHENS	OK	UNNAMED CREEK	03/03/93
K 160	162617	KGS	QTR. NE, SEC. 20, T-2S, R-7W 1.5 MILES E, THEN .5 MILES N, THEN .5 MILES W OF COMANCHE	STEPHENS	OK	SMALL UNNAMED CREEK	03/17/93
K 161	163527 F93-1935	KGS	QTR. SE, SEC. 2, T-2N, R-3W 2 MILES SE OF PRUITT	CARTER	OK	UNNAMED CREEK > CONSERVATION LAKE	03/22/93
K 162	163617 F93-1940	KGS	QTR. SW, SEC. 9, T-2S, R-2W	CARTER	OK	UNNAMED CREEK	03/23/93

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 163	163846 F93-1956	KGS	SEC. 1, T-10N, R-8W HWY 81 RIVER BRIDGE NORTH OF MINCO SEC. 18, T-10N, R-5W	GRADY	OK	SOUTH CANADIAN RIVER	03/24/93
K 164	164515	KGS	QTR. SE, SEC. 10, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK	03/28/93
K 165	174826	KGS	ONE MILE SOUTH OF NORMAN WASTEWATER TREATMENT PLANT ON SOUTH CANADIAN RIVER AND WEST OF ASPHALT PLANT, STRAIGHT EAST OF DAVID J. PERRY AIRPORT QTR. NW, SEC. 20, T-8N, R-2W SEC. 17, T-8N, R-2W	CLEVELAND	OK	SOUTH CANADIAN RIVER	05/19/93
K 166	175732	KGS	QTR. SW, SEC. 15, T-17N, R-5E	PAYNE	OK	DRY CREEK BED	05/24/93
K 167	178829	KGS	QTR. NW/NW/SE, SEC. 31, T-9N, R-3W	MCCLAIN	OK	TRIBUTARY OF SOUTH CANADIAN RIVER	06/08/93
K 168	178817 F93-2951	KGS	QTR. NW/NW/NE, SEC. 17, T-10N, R- 10W	CADDO	OK	MEDICINE CREEK > UNKNOWN CANYON	06/08/93
K 169	184985	KGS	QTR. SE/SE, SEC. 33, T-5N, R-6E	PONTOTOC	OK	UNNAMED CREEK	07/01/93
K 170		KGS	QTR. SW/NE, SEC. 30, T-25N R-14E	WASHINGTON	OK	CURL CREEK	07/14/93
K 171	187284	KGS	QTR. NW, SEC. 30, T-25N, R-13E	WASHINGTON	OK	CANEY RIVER	07/19/93
K 172		KGS	QTR. NE, SEC. 20, T-2S, R-7W	STEPHENS	OK	DRY CREEK BED > UNNAMED CREEK	09/17/93

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 173	198823 199536	KGS	QTR. SW, SEC. 21, T-24N, R-10E	OSAGE	OK	FOUR MILE CREEK	09/21/93
K 174	198898 F93-4259	KGS	QTR. NE/NW, SEC. 13, T-5N, R-5E	SEMINOLE	OK	SALT CREEK > SALT CREEK RESERVOIR	09/22/93
K 175		KGS	SEC. 5, T-1S, R-8W	STEPHENS	OK	UNNAMED CREEK	10/31/93
K 176	208055 F94-0564	KGS	QTR. SW, SEC. 6, T-14N, R-6W HWY 81, OKARCHE, 5 MILES E ON COUNTY LINE RD., 3/4 MILES SOUTH	CANADIAN	OK	UNNAMED CREEK > POND (CANADIAN GOOSE KILLED)	11/15/93
K 177	208775	KGS	QTR. SW, SEC. 20, T-6S, R-2E	LOVE	OK	UNNAMED CREEK > HICKORY CREEK	11/19/93
K 178	209868 F94-0656	KGS	QTR. NE, SEC. 2, T-7N, R-2E	POTTAWATOMIE	OK	UNNAMED CREEK > POSSIBLY TO SALT CREEK	11/26/93
K 179	211157	KGS	QTR. NW, SEC. 31, T-5N, R-5E	PONTOTOC	OK	DITCH > UNNAMED CREEK	12/06/93
K 180		KGS	SEC. 31, T-29N, R-10E	OSAGE	OK	UNNAMED POND / CREEK	12/06/93
K 182	212549	KGS	QTR. NE/SW, SEC. 35, T-5N, R-4E	PONTOTOC	OK	UNNAMED CREEK	12/14
K 183		KGS	QTR. NW, SEC. 36, T-1S, R-5W	STEPHENS	OK	CREEK / STREAM	12/17/93
K 184	214584	KGS	SEC. 24, T-2N, R-8W 2 MILES EAST OF HWY 81 ON HWY IN MARLOW	STEPHENS	OK	HELL CREEK	12/29/93
K 185	214787 F94-1134	KGS	QTR. NW, SEC. 2, T-2S, R-5W	STEPHENS	OK	UNNAMED CREEK	01/01/94

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 186	215545	KGS	SEC. 34, T-24N, R-9E	OSAGE	OK	TWO MILE CREEK	01/06/94
K 187	219409	KGS	QTR. NW, SEC. 29, T-26N, R-8E	OSAGE	OK	SOUTH BIRD CREEK	01/29/94
K 188	222481 F94-1831	KGS	QTR. NE, SEC. 8, T-5S, R-1E	CARTER	OK	UNNAMED CREEK > HICKORY CREEK	02/19/94
K 189		KGS	QTR. NW, SEC. 9, T-2S, R-2W	CARTER	OK	TRIBUTARY TO BEAR CREEK	02/20/94
K 190	224003	KGS	QTR. SE, SEC. 11, T-2S, R-3W	CARTER	OK	UNNAMED CREEK > UNKNOWN	03/01/94
K 191	224143	KGS	QTR. SW, SEC. 15, T-5S, R-1W	CARTER	OK	UNNAMED CREEK > WALNUT BAYOU CREEK	03/02/94
K 192	230814	KGS	QTR. NW, SEC. 28, T-5N, R-6E	PONTOTOC	OK	UNNAMED CREEK	03/19/94
K 193		KGS	QTR. NE/NW, SEC. 19, T-7N, R-1W	CLEVELAND	OK	UNNAMED CREEK	04/01/94
K 194	238014	KGS	QTR. NW, SEC. 30, T-1S, R-3W	CARTER	OK	UNNAMED FARM POND	05/04/94
K 195		KGS	QTR. SE, SEC. 20, T-5N, R-4W	McCLAIN	OK	UNNAMED POND	05/04/94
K 196	238225	KGS	WEBB CITY STATION ON HWY 11	OSAGE	OK	DRY CREEK BED	05/05/94
K 197	238852	KGS	QTR. NE/NE, SEC. 24, T-5N, R-3W	MCCLAIN	OK	UNNAMED CREEK	05/10/94

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FIRST AMENDED SCHEDULE A

SPELL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 198	240445	KGS	QTR. SE, SEC. 2, T-7N, R-2E TRIBBEY STATION	POTTAWATOMIE	OK	COON CREEK	05/21/94
K 199	245317	KGS	QTR. SE, SEC. 13, T-16N, R-13E	TULSA	OK	UNNAMED STREAM	06/21/94
K 200	259249	KGS	QTR. NE, SEC. 1, T-7S, R-2E	LOVE	OK	UNNAMED TRIBUTARY TO HICKORY CREEK (IN GAME REFUGE)	09/06/94
K 201	260855	KGS	QTR. NE/SE, SEC. 4, T-2S, R-3W	CARTER	OK	CADDO CREEK (SPILL OVER 26 MILES) UNKNOWN CREEK > WASHITA RIVER	09/16/94
K 202	266339	KGS	SEC. 3, T-4S, R-3W	CARTER	OK	WHISKEY CREEK	10/21/94
K 203	267957 F95-0465	KGS	QTR. SW, SEC. 6, T-7S, R-3W 5 MILES NE OF MARIETTA	LOVE	OK	UNNAMED CREEK > HICKORY CREEK	11/01/94
K 204	268040 F95-0475	KGS	SEC. 11, T-4N, R-6W	GRADY	OK	UNNAMED CREEK	11/02/94
K 205	268612 F95-0526	KGS	SEC. 4, T-1S, R-3W HWY 76	CARTER	OK	WILD HORSE CREEK > WASHITA RIVER	11/07/94
K 206	270381 F95-0710	KGS	QTR. NW, SEC. 31, T-6S, R-3E	LOVE	OK	TRIBUTARY OF HICKORY CREEK	11/20/94
K 207	279685	KGS	SEC. 25, T-14N, R-7E	OSAGE	OK	UNKNOWN WASH > BIG HOMINY CREEK	02/13/95
K 208	279987	KGS	QTR. SW, SEC. 30, T-8N, R-1W, NEAR MCGUIRE ROAD IN NOBLE, OK	CLEVELAND	OK	UNNAMED CREEK	02/15/95
K 209	280599	KGS	SEC. 18, T-23N, R-8W	OSAGE	OK	DRY CREEK BED	02/20/95

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 210	282530	KGS	QTR. NE, SEC. 7, T-4S, R-2W, WILSON JCT	CARTER	OK	WALNUT CREEK	03/08/95
K 211		KGS	7-8 MILES NORTH OF NOCONA	MONTAGUE	TX	WET/DRY CREEK	05/17/90
K 212	23701	KR	SUNTIDE ROAD	NUECES	TX	GULF OF MEXICO	05/25/90
K 213		KGS	15 MILES EAST OF GUTHRIE	KING	TX	BUFFALO CREEK	05/31/90
K 214	26732	KGS	BARRY CREEK, BETWEEN LYNAS AND CALDWELL	BURLESON	TX	BARRY CREEK	06/13/90
K 215	32162	KGS	CB STEWART SURVEY ON FM 1314, 9 MILES SOUTH OF CONROE ON FM 1314	MONTGOMERY	TX	SANDY BRANCH CREEK	07/23/90
K 216		KGS	AT BAIRD, TURN N ON 283, TURN E ON FM 576	CALLAHAN	TX	STOCK POND	10/02/90
K 217		KGS	3 MILES SOUTHWEST OF LONGVIEW; SLOUGH ADJACENT TO HAWKINS CREEK, McMURRAY LEASE S OF U.S. 80, N OF GOLF COURSE	GREGG	TX	DRAINAGE DITCH > SLOUGH > STOCK POND > HAWKINS CREEK	12/08/90
K 218	52667	KR	TULE LAKE WETLANDS, APPROX 2 MILES E OF SUNTIDE ROAD & IMMEDIATELY S OF RAILROAD TRACK	NUECES	TX	CORPUS CHRISTI INNER HARBOR, NUECES- RIO GRANDE COASTAL	12/27/90
K 219	52740	KGS	KOCH GATHERING SYSTEMS BARGE DOCKS INGLESIDE, TX	SAN PATRICIO	TX	CORPUS CHRISTI BY SHIP CHANNEL	12/28/90

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 220		KGS	WITHIN CITY LIMITS OF SHERMAN	GRAYSON	TX	OIL FLOWED INTO A "DRAINAGE WAY"	01/02/91
K 221	56394	KGS	FROM HWY 42 N TURN RIGHT ON OLD HWY 80, 4 MILES, TURN LEFT ON WHATLEY (5 MILES E OF WHITE OAK, NORTH OF PAYNE ROAD)	GREGG	TX	STOCK POND	01/24/91
K 222	56671	KGS	HAWKINS CREEK AT GEORGE RITCHIE ROAD IN WHITE OAK	GREGG	TX	HAWKINS CREEK (6 MILES N OF SABINE RIVER)	01/26/91
K 223		KGS	6 MILES NE OF CAPPS CORNER	COOKE	TX	MOUNTAIN CREEK, TRINITY	01/30/91
K 224	60093	KGS	6 MILES SE OF DIME BOX ON COUNTY ROAD 430	LEE	TX	STOCK POND	02/18/91
K 225	63529	KGS	FR 141 (JOHN DOBBINS)	LEE	TX	STOCK POND	03/14/91
K 226		KGS	BLOCK (J.Y. CASSTILLO)	MONTAGUE	TX	STOCK POND	04/01/91
K 227	68004	KGS	FM 1314	MONTGOMERY	TX	CRYSTAL CREEK	04/14/91
K 228		KGS	NEAR LEVERETT'S CHAPEL, TURN RIGHT ON DON EVERETT RD., GO TO AMERICAN PLANT RD., TURN RIGHT, 1ST CATTLEGUARD (YELLOW & BLACK) GO .5 MILES	RUSK	TX	TURKEY CREEK	05/14/91

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 229		KGS	FROM GUTHRIE TO ASPERMONT, 12 MILES PAST CROTON RANCH CATTLEGUARD; AT 2ND CATTLEGUARD, GO TO COMB. LOCK 35 67 THRU GATE, 8 MILES	KING	TX	CROTON CREEK	05/26/91
K 230		KGS	N OF ASPERMONT, TURN RIGHT AT FLASHING LIGHT, GO 2 MILES, TURN RIGHT AT HOUSE, GO PAST ASPERMONT AIRPORT 1 1/2 MILE, TURN LEFT INTO GATE, GO 1/4 MILES AND TURN RIGHT AT PUMP JACK. FOLLOW ROAD	STONEWALL	TX	CREEK LEADING TO BRAZOS RIVER	06/12/91
K 231		KGS	G.W. THOMPSON	MONTAGUE	TX	MADDOX CREEK	06/14/91
K 232		KGS	M. LOPEZ, SEC. 112, T-16N, R-11E	WEBB	TX	CREEK > STOCK POND	07/06/91
K 233		KGS	WEST OF MORAN ON FM 576, GO 3 MILES WHEN ROAD MAKES S CURVE, TAKE COUNTY ROAD GOING SOUTH, 5 MILES, CROSS CREEK & 2 CATTLEGUARDS; TURN RIGHT AT 2ND CATTLEGUARD, GO THRU GATE, TURN LEFT	CALLAHAN	TX	DRY CREEK BED	07/23/91
K 235		KGS	BUFFALO BRAZOS & CO.	THROCKMORTON	TX	STOCK POND	07/24/91
K 236		KGS	OFF AVE E IN ALGOA	GALVESTON	TX	DICKINSON BAYOU	07/29/91

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 238	83394	KGS	OFF OF AMERICAN PLANT RD MEREDITH MCCABE SURVEY, SOUTH OF KILGORE	RUSK	TX	RABBIT CREEK	08/12/91
K 239	85144	KGS	HWY 42 ON THE WEST SIDE, 7 MILES SOUTH OF KILGORE	RUSK	TX	GROUND > RABBIT CREEK	08/23/91
K 240		KGS	5 MILES N OF FORT GRIFFIN ON STANLEY IRWIN'S PROPERTY	THROCKMORTON	TX	PLUM BRANCH CREEK	09/16
K 241		KGS	OUT OF GUTHRIE GO TOWARD KNOX CITY, 4 MILES BEFORE YOU GET TO A CAFE -- BATEMAN RANCH, TURN LEFT AT MASTERSON RANCH HEAD	KING	TX	LITTLE WICHITA RIVER	09/26/91
K 242	90615	KGS	ON HWY 42	GREGG	TX	SLOUGH	10/01/91
K 243	91375	KGS	100 YDS N OF HWY 80, 1 MILE E OF GLADEWATER	GREGG	TX	MOODY CREEK	10/05/91
K 244	91195	KGS	7 MILES N OF KILGORE NEAR HWY 42 AND MERRILL'S LAKE ROAD	GREGG	TX	DRAINAGE SLOUGH AREA > SABINE RIVER (CITY WATER SUPPLY)	10/06/91
K 245	93529	KGS	8 MILES N OF KILGORE ON HWY 42	GREGG	TX	HAWKINS CREEK	10/23/91
K 246		KGS	CITY OF SHERMAN, EAST SIDE 1 MILE S OF HWY 82 AT CREEK	GRAYSON	TX	UNNAMED CREEK > RED RIVER	10/29/91
K 247		KGS	GO I-20W, TAKE SYLVESTER ROAD CUT-OFF, CROSS OVER, GO WEST ON FEEDER ROAD, GO 1 MILE, GATE ON LEFT	NOLAN	TX	UNKNOWN CREEK	10/31/91
K 248		KGS	7 MILES N OF ST. JO	MONTAGUE	TX	TRIBUTARY OF MOUNTAIN CREEK	11/03/91

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 249		KGS	LAKE GRAHAM	YOUNG	TX	LAKE GRAHAM	11/04/91
K 251	96598	KGS	AMOCO WHATLEY LEASE B	GREGG	TX	WASH INTO HAWKINS CREEK	11/17/91
K 252	98606	KGS	OFF OF HWY 80, 2 MILES N ON WHITE OAK ROAD, 2 MILES E ON TUTTLE RD	GREGG	TX	HAWKINS CREEK	12/06/91
K 253		KGS	1 BLOCK S OF HWY 82 ON HWY 1417	GRAYSON	TX	UNNAMED CREEK	12/06/91
K 254		KS	FM 517 ON S SIDE FR SAN LEON, MARSHALL WELL, WACKER SEAGULL PRODUCERS	GALVESTON	TX	DITCH > BAYOU (HL&P FEED CANAL)	12/20/91
K 255		KGS	HUBBARD CREEK, 8 MILES N OF MORAN, TX	SHACKLEFORD STEPHENS	TX	HUBBARD CREEK	12/24/91
K 256	100979	KGS	NORTH OF WHITE OAK ON WHITE OAK ROAD TO TURTLE ROAD, RIGHT ON WHATLEY ROAD, GO SOUTH, 1ST LEASE ROAD TO LEFT	GREGG	TX	HAWKINS CREEK	12/27/91
K 257	101598	KGS	SHELL CAMP RD AND HWY 80, 5 MILES EAST OF WHITE OAK ON HWY 80	GREGG	TX	MOODY CREEK > SABINE RIVER	01/04
K 258	102386	KR	20 MILES SOUTH OF SAN ANTONIO 1/2 EAST OF STATE HWY 181, 5 MILES NORTH OF FLORESVILLE, TX	WILSON	TX	GROUNDWATER CONTAMINATION, DRY WASH > POND	01/10/92
K 259	103738	KGS	E ON HWY 80, 3 MILES E OF GLADEWATER	GREGG	TX	MOODY CREEK	01/21/92

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 260	106956	KR	CORPUS CHRISTI INNER HARBOR DOCK #9, SUNTIDE ROAD	NUECES	TX	CORPUS CHRISTI INNER HARBOR	02/15/92
K 261	107129	KR	CORPUS CHRISTI PORT, OIL DOCK #9	NUECES	TX	CORPUS CHRISTI INNER HARBOR	02/17/92
K 262	108300	KGS	NEAR HW 87, 1.10 MILES W OF NIXON, TEXAS	WILSON	TX		02/26/92
K 263	108586 F92-1711	KGS	8 MILES NORTH OF FREER ON HWY 16, TONAS RANCH	DUVAL	TX	SAN YGNACIO CREEK	02/28/92
K 264	109055	KGS	HWY 80 AT MOODY CREEK 2 MILES E OF GLADEWATER	GREGG	TX	MOODY CREEK	03/03/92
K 265	110034	KR	CORPUS CHRISTI PORT, OIL DOCK #8, SUNTIDE RD	NUECES	TX	CORPUS CHRISTI PORT	03/10/92
K 266	110981	KGS	TETTLER RD	GREGG	TX	UNNAMED CREEK	03/18/92
K 268	116279	KGS	EAST TEXAS FIELD, MOODY CREEK AT HWY 80	GREGG	TX	MOODY CREEK	04/30/92
K 269		KGS	1 MILE NORTH OF NUECES RIVER ON WEST SIDE OF I-37; ENTER MAIN WELDER RANCH GATE, GO TO 1ST TANK BATTERY	SAN PATRICIO	TX	GROUNDWATER CONTAMINATION, NEAR HONDO CREEK AND NUECES RIVER	06/01/92
K 270		KGS	CARROLL CREEK FROM UPSTREAM OF HWY 199 TO BEYOND HWY 380	JACK WISE	TX	CARROLL CREEK > TRINITY RIVER	06/02/92
K 271		KGS	SAXON ROAD, NEAR LEVIRITT'S CHAPEL, SE OF KILGORE	RUSK	TX	TRIBUTARY TO RABBIT CREEK	06/13/92

FIRST AMENDED SCHEDULE A

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SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 272	122364	KGS	1.9 MILES E OF U.S. 123 ONTO CR 233, THEN GO 2.1 MILES TO FABIAN VEILA LEASE	KARNES	TX	MULTIFEST CREEK > SAN ANTONIO RIVER	06/17/92
K 273	128059 F92-3444	KGS	GLADEWATER EAST - 2 MILES EAST ON HWY 80 AND 2 MILES SOUTH ON LOCKER - PLANT RD	GREGG	TX	CREEK > SABINE RIVER	07/21/92
K 274	128493 F92-3572	KGS	25 MILES NE OF BRECKENRIDGE	YOUNG	TX	CREEK BED, CLEAR FORK OF BRAZOS RIVER	07/23/92
K 276	139319	KGS	HWY 31 AND 135 JUNCTION	GREGG	TX	DRY CREEK BED / DRY CREEK TRIBUTARY OF LITTLE RABBIT CREEK	10/05/92
K 277	148470 148827	KGS	BRADLEY RANCH, 18 MILES S/SW OF KNOX CITY	STONEWALL	TX	DITCH AND CREEK DRAWER > NORTH CROTON CREEK > WELLINGTON CREEK	12/10/92
K 278	149052	KGS	OFF WATLEY RD	GREGG	TX	UNNAMED CREEK AND POND	12/14/92
K 279	150961	KGS	H L WILKERSON SURVEY A1113, 3/4 MILES SOUTH OF BULCHER AT MOUNTAIN CREEK	MONTAGUE	TX	BRANCH OF MOUNTAIN CREEK	12/29/92
K 281	156859	KGS	WHITE OAK RD NEAR HARLEY RDGE RD	GREGG	TX	UNNAMED CREEK > HAWKINS CREEK	02/05
K 282	156918 F93-1404	KGS	4 MILES W OF LYON ON FM 60, RIGHT ON CR 405, GO TO END OF ROAD	BURLESON	TX	HICKORY CREEK, TWO SEPARATE UNNAMED CREEKS, A STOCK POND AND A POND IN FRONT OF A RESIDENCE	02/06/93
K 285	184723	KGS	2 MILES NE OF WHITE OAK, 1/4 MILE SOUTH OF GEORGE RITCHIE ROAD	GREGG	TX	HAWKINS CREEK	07/06/93

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FIRST AMENDED SCHEDULE A

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 286	210209	KGS	WEST SIDE OF HWY 42 SOUTH OF KILGORE ON HWY 42	RUSK	TX	UNNAMED CREEK	11/29/93
K 287		KGS	PAINE RANCH	MONTAGUE	TX	SALT CREEK	12/29/93
K 288	223156	KGS	KILGORE, HWY 31, 3/4 MILES EAST OF HWY 135	GREGG	TX	RABBIT CREEK	02/23/94
K 289	230173	KR	SUNTIDE ROAD, OIL DOCK #9	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	03/16/94
K 290	237766	KGS	57 BLOCK D ETRC SURVEY, 5 MILES NW OF ALBANY NEAR FM 1084	SHACKELFORD	TX	COOK CREEK	05/03/94
K 291	241271	KGS	FM 1073, 4 MILES FROM ALBANY	SHACKELFORD	TX	UNNAMED CREEK > HUBBARD CREEK	05/27/94
K 292	241439	KGS	N OF LONGVIEW ON HWY 1845 HAWKINS CREEK	GREGG	TX	HAWKINS CREEK	05/28/94
K 293	241995	KGS	5 MILES S OF CONROE ON 3083 FARM ROAD	MONTGOMERY	TX	CRYSTAL CREEK	06/02/94
K 294	242164	KGS	THOMPSON ROAD	GREGG	TX	SMALL UNNAMED CREEK > HAWKINS CREEK	06/03/94
K 295	242966	KGS	5 MILES EAST OF MURRAY, TAKE FIRST GATE ON RIGHT AFTER RURAL WATER TANKS, JACKSON RANCH	YOUNG	TX	TRIBUTARY TO FISH CREEK	06/08/94
K 296	251734	KGS	RANSOME HOUSE A-244 DIESEL	MONTGOMERY	TX	CRYSTAL CREEK	07/26/94
K 298	255040	KGS	EAST TEXAS FIELD, HWY 1845	GREGG	TX	HAWKINS CREEK > SABINE RIVER	08/12/94

FIRST AMENDED SCHEDULE A

- 26 -

SPIII#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 299	260980	KGS	UNNAMED CREEK LEADS TO UNNAMED POND	COOKE	TX	UNNAMED CREEK / UNNAMED POND	09/16/94
K 300	263545	KGS	2 MILES NORTH OF MORAN UNIVERSITY LAND SURVEY	SHACKELFORD	TX	CREEK BED	10/02/94
K 301	263973	KR	SUNTIDE ROAD	NUECES	TX	CORPUS CHRISTI SHIP CHANNEL	10/05"
K 302	264456 264419	KGS	KOCH REFINERY 3 MILES UP DRAINAGE DITCH FROM SHORE OF NUECES BAY WEST OF PORTLAND, CR 72	SAN PATRICIO	TX	BROKEN 10" PIPELINE; 400 BBLs. OF NIGERIAN CRUDE WAS DISCHARGED INTO THE NUECES AND CORPUS CHRISTI BAYS	10/08/94
K 303	265735	KGS	136 YARDS SOUTH OF HWY 359 QUARTER MILE EAST OF FM 649	WEBB	TX	DRY CREEK BED	10/17/94
K 305	270797 F95-0757	KGS	FM 180	LEE	TX	SMALL CREEK	11/23/94
K 306	272157 F95-0920 272193 F95-0928	KGS	NEAR THE INTERSECTION OF F.M. 141 & C.R. 430, SE OF DIME BOX	LEE	TX	UNNAMED CREEK > YEGUA CREEK > LAKE SOMERVILLE	12/06/94
K 307	272175 F95-0923	KGS	4 MILES NW OF SHERMAN	GRAYSON	TX	UNNAMED CREEK	12/06/94
K 308	273760 F95-1125	KGS	CONROE FIELD CONROE, TX	MONTGOMERY	TX	CRYSTAL CREEK	12/19/94
K 309	274992 F95-1272	KGS	SECTION 5 OF COMANCHE INDIAN RESERVE, THROCKMORTON, TX	THROCKMORTON	TX	UNNAMED CREEK > BRAZOS RIVER	12/31/94
K 310	276128 F95-1406	KGS	4 MILES SOUTH OF WHITE OAK, TX, OFF HWY 42	GREGG	TX	UNNAMED CREEK	01/12/95

FIRST AMENDED SCHEDULE A

- 27 -

SPILL#	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
K 311	276902 F95-1504	KGS	1/2 MILE WEST OF FM 3083 ON TEXACO ROAD, 5 MILES SE OF CONROE, TX	MONTGOMERY	TX	CRYSTAL CREEK	01/19/95
K 312	277052 F95-1520	KGS	HWY 180, 3 MILES EAST OF GLADEWATER, TX	GREGG	TX	DRAINAGE DITCH > MOODY CREEK	01/20/95
K 313	277940	KGS	COUNTY ROAD 169	FAYETTE	TX	SPRING CREEK	01/25
K 314	278236	KGS	15 MILES NORTH OF MUEENSTER	COOKE	TX	CREEK > MOUNTAIN CREEK	01/31/95
K 316	283073	KGS	5 MILES SOUTH OF FALLS CITY, TX	KARNES	TX	CREEK BED	03/13/95
K 317	286138	KGS	3 MILES EAST OF TILDEN	MCMULLEN	TX	SLOUGH / POND / LA JARITA CREEK	04/07/95

Dated: April 24, 1996

442

UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF OKLAHOMA

FILED

JUL 28 1997 *SA*

Phil Lombardi, Clerk
U.S. DISTRICT COURT

Di
UNITED STATES OF AMERICA,)

Plaintiff,)

v.)

Civil Action No.

KOCH INDUSTRIES, INC.,)
KOCH PIPELINE CO., L.P.,)
KOCH GATHERING SYSTEMS, INC.,)

Defendants.)

97CV687 B (W)

COMPLAINT

The United States of America, by the authority of the Attorney General of the United States and through the undersigned attorneys, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), and the United States Coast Guard, ("Coast Guard") through the Secretary of the Department of Transportation, files this complaint and alleges as follows:

I. INTRODUCTION

1. This is a civil action brought pursuant to the Clean Water Act ("CWA"), 33 U.S.C. § 1251 et seq., as amended by the Oil Pollution Act of 1990 ("OPA"), Pub. L. 101-380, 104 Stat. 484, seeking injunctive relief and civil penalties incurred by the United States as a result of the discharge of crude oil and petroleum products into navigable waters or adjoining shorelines of the United States.

CH
10/5/01

II. JURISDICTION, VENUE AND NOTICE

2. This Court has jurisdiction over this action under 28 U.S.C. §§ 1331, 1345, 1355 and 1395(a); Sections 309(b) and 311(b)(7)(E) of the CWA, 33 U.S.C. §§ 1319(b) and 1321(b)(7)(E) and Sections 1002 and 1017(b) of the OPA, 33 U.S.C. §§2702, and 2717(b).

3. Authority to bring this action is vested in the United States Department of Justice by 28 U.S.C. §§ 516 and 519 and 33 U.S.C. § 1366.

4. Venue is proper in the Northern District of Oklahoma pursuant to 28 U.S.C. §§ 1391 and 1395(a); Section 309(b) and 311(b)(7)(E) of the CWA, 33 U.S.C. §§ 1319(b) and 1321(b)(7)(E), inasmuch as it is the judicial district in which each defendant does business.

5. Notice of the commencement of this action has been given to the States of Texas, Oklahoma, Kansas and Louisiana, pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b).

III. DEFENDANTS

6. Defendant, Koch Industries, Inc., is a Kansas corporation that conducts business in Oklahoma.

7. Koch Industries, Inc., is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

8. Defendant, Koch Pipeline Co., L.P. is a Delaware limited partnership that conducts business in Oklahoma.

9. Koch Pipeline Co., L.P. is an "owner/operator" of "onshore facilities" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

10. Defendant, Koch Gathering Systems, Inc. is a Kansas corporation that conducts business in Oklahoma.

11. Koch Gathering Systems, Inc. is an "owner/operator" of "onshore facilities" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11) and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

12. Koch Gathering Systems, Inc. merged into Koch Pipeline Co., L.P. in August, 1995.

IV. THE CWA REGULATORY SCHEME FOR DISCHARGES OF OIL

Prohibition of Oil Discharges

13. Section 301(a) of the CWA, 33 U.S.C. § 1311(a), prohibits, except as otherwise authorized, the discharge of any pollutant, including oil, by any person. Section 502(12) of the CWA, 33 U.S.C. 1362(12), defines "discharge of a pollutant" to include "any addition of any pollutant to navigable waters from any point source." Oil is a pollutant within the meaning of Section 502(6) of the CWA, 33 U.S.C. § 1362(6).

14. Section 311(b)(3) of the CWA, 33 U.S.C. § 1321(b)(3), prohibits the discharge of oil into or upon the navigable waters of the United States and adjoining shorelines in such quantities as the President determines may be harmful to the public health or welfare or environment of the United States.

15. Pursuant to Section 311(b)(4) of the CWA, 33 U.S.C. § 1321(b)(4), the President, through a delegation to EPA, Exec. Order No. 11735, 38 Fed. Reg. 21243 (Aug. 7, 1973), has determined by regulation that the quantities of oil that may be harmful to the public health or welfare or environment of the United States include discharges of oil that, inter alia, cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines. 40 C.F.R. § 110.3.

B. Injunctive Relief

16. Section 309(b) of the CWA, 33 U.S.C. § 1319(b), authorizes EPA to commence a civil action for appropriate relief, including a permanent or temporary injunction, for any violation for which he is authorized to issue a compliance order under [Section 309(a)]. [Bracketed material supplied.]

17. Section 309(a) of the CWA, 33 U.S.C. § 1319(a), authorizes, inter alia, the issuance of compliance orders for discharges of pollutants prohibited under Section 301(a) of the CWA, 33 U.S.C. 1311(a).

c. Civil Penalties

18. With respect to the discharges of oil alleged in Schedule 1 of this complaint, Section 311(b)(7) of the CWA, 33 U.S.C. § 1321(b)(7), as amended by OPA, provides that:

Any person who is the owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged in violation of ... [Section 311(b)(3) of the CWA], shall be subject to a civil penalty in an amount up to \$25,000 per day of violation or an amount up to \$1,000 per barrel of oil or unit of reportable quantity of hazardous substances discharged. [Bracketed material supplied.]^{1/}

19. With respect to the discharges of oil alleged in Schedule 1 in the complaint, Section 311(b)(7)(D) of the CWA, 33 U.S.C. § 1321(b)(7)(D) as amended by OPA provides that:

In any case in which a violation of...[Section 311(b)(3)] was the result of gross negligence or willful misconduct of a person...the person shall be subject to a civil penalty of not less than \$100,000, and not more than \$3,000 per barrel of oil or unit of reportable quantity of hazardous substance discharged. [Bracketed material supplied.]

V. FACTS GIVING RISE TO LIABILITY

20. The named defendants (collectively "Koch") own and operate underground crude oil pipelines and other onshore facilities throughout the states of Texas, Louisiana, Oklahoma and Kansas.

¹ The statutory penalty amounts are periodically amended for inflation as mandated by the Debt Collection Improvement Act of 1996. Currently, the maximum civil penalty for oil spills under this provision is \$1,100 per barrel. The alternative daily maximum has been increased to \$27,500. 62 Fed. Reg. p. 35038-35041.

21. On numerous occasions in the past 5 years, (including but not limited to those spills specifically alleged in Schedule 1 to this Complaint) the defendants' pipelines and onshore facilities in the named states have ruptured causing oil and/or hazardous substances to spill into the environment and into the waters of the United States or the adjoining shorelines. These ruptures and spills are continuing. Schedule 1 to this Complaint lists the date, location (including county and state), affected waterway, and the National Response Center report number of each spill for which civil penalties and injunctive relief are sought pursuant to this action.

VI. CLAIMS FOR RELIEF

A. First Claim: Injunctive Relief

22. Paragraphs 1 through 21 are realleged and incorporated by reference.

23. Defendants' discharge of oil and/or hazardous substances, into or upon the navigable waters of the United States or adjoining shorelines in such quantities as have been determined to be harmful to the public health or welfare or environment of the United States violate Section 311(b)(3) of the CWA, 33 U.S.C. § 1321(b)(3), and Section 301 of the CWA, 33 U.S.C. § 1311(a) and subjects defendants to injunctive relief pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b). Unless restrained by this Court, defendants will continue to discharge oil into the waters of the United States in violation of the CWA and OPA.

B. Second Claim: Civil Penalties

24. Paragraphs 1 through 21 are realleged and incorporated by reference.

25. Defendants' discharges of oil and/or hazardous substances as alleged herein which occurred violate Sections 301(a) and 311(b)(3) of the CWA, 33 U.S.C. §§ 1311(a) and 1321(b)(3) and, pursuant to Section 311(b)(7)(A) of the CWA, 33 U.S.C. § 1321(b)(7)(A), subjects defendants to a civil penalty of up to \$1,000 per barrel of oil discharged.

26. Defendants' discharges of oil and/or hazardous substances as alleged herein which were the result of defendants' gross negligence or willful misconduct and which occurred in violation of Sections 301(a) and 311(b)(3) of the CWA, 33 U.S.C. §§ 1311(a) and 1321(b)(3) and, pursuant to Section 311(b)(7)(D) of the CWA, 33 U.S.C. 1321(b)(7)(D), subjects defendant to a civil penalty of not less than \$100,000 and up to \$3,000 per barrel of oil discharged.

27. Section 309(b) of the CWA, 33 U.S.C. § 1319(b), authorizes the commencement of a civil action for appropriate relief, including a permanent or temporary injunction. Unless restrained by this Court, defendants will continue to discharge oil in violation of the CWA and OPA.

PRAYER FOR RELIEF

WHEREFORE, plaintiff, the United States of America, respectfully requests that this Court enter judgment against the defendants for:

a. Such injunctive relief pursuant to Section 309(b) of the CWA as may be necessary to prevent future releases and protect and restore the waters of the United States; and

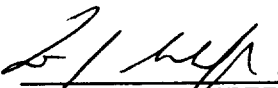
b. Impose civil penalties on defendants of up to \$1,000 per barrel of oil discharged in violation of Section 311(b)(3) for all spills alleged in the Complaint and all spills which occur or continue after the filing of this complaint;

c. Impose civil penalties on defendant of not less than \$100,000 and up to \$3,000 per barrel of oil discharged in violation of Section 311(b)(3) that were the result of defendants' gross negligence or willful misconduct;

c. Enter an Order requiring Koch to 1) report all spills of oil into waters of the United States to the National Response Center and 2) to accurately report the quantity of each spill.

d. Such other relief as the United States may be entitled.

Respectfully submitted,



LOIS J. SCHIFFER
Assistant Attorney General
Environment and Natural Resources
Division



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Trial Attorney
Environmental Enforcement Section
United States Department of Justice
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STEPHEN C. LEWIS
United States Attorney



Phil Pinnell
Assistant United States Attorney

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Dallas, Texas 75202

Julie Van Horn
U.S. Environmental Protection Agency
Region VII
726 Minnesota Ave.
Kansas City, KS 66101

SCHEDULE 1

SPILL #	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
1	335179	KGS	SEC.-NE 6, R-19W, T-17S, 7 MILES WEST OF LACROSSE	RUSH	KS	BIG TIMBER CREEK	4/7/96
2	289247	KGS	GROSS TETE, LA	IBERVILLE	LA	UPPER GRAND RIVER	4/29/95
3	358527	KGS	5 MILES NORTH OF HOMINY	OSAGE	OK	HOMINY CREEK	8/27/96
4	307676	KGS	SEC.-27, R-5W, T-1S	STEPHENS	OK	WILD HORSE CREEK > LAKE TEXOMA	9/16/95
5	354295	KGS	SEC.-17, R-5W, T-2N	STEPHENS	OK	UNNAMED CREEK LEADING TO RUSH CREEK	7/31/96
6	298408	KGS	CLEVELAND	OSAGE	OK	UNNAMED CREEK	7/5/95
7	348927	KGS	SEC.-35, R-5W, T-3N	GRADY	OK	UNNAMED CREEK AND STOCK TANK - PART OF THE RUSH CREEK WATERSHED PROJECT	6/25/96
8	144252	KGS	SEC.-32, R-10E, T-22N	OSAGE	OK	WILDHORSE CREEK	11/10/92
9	308214	KP	SEC.-6, R-2W, T-8S	LOVE	OK	TRIBUTARY TO RED RIVER	9/21/95
10	308425	KGS	SEC.-17, R-10E, T-24N	OSAGE	OK	BIRCH CREEK LEADING TO BIRCH LAKE	9/22/95
11	293852	KGS	SIVELLSBEND, GAINESVILLE, TX	COOKE DUNCAN	TX OK	RED RIVER	6/1/95
12	360289	KP	LAT -33 44 01 N; LONG- 96 40 59 W 5.7 MILES WEST OF SHERMAN	GRAYSON	TX	UNNAMED CREEK	9/8/96
13	351075	KGS	LAT-32 57 01 N; LONG-99 09 43 W 9 MILES SOUTHWEST OF WOODSON	SHACKELFORD	TX	SHIRLEY CREEK BRANCH	7/9/96

- 2 -

SCHEDULE 1

SPILL #	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
14	314836	KGS	COUNTY ROAD 128 IN RURAL AREA 8 MILES SOUTH OF CALDWELL	BURLESON	TX	PIN OAK CREEK	11/20/95
15	386988	KP	EDMOND J FORD RANCH, WOODSBORO	REFUGIO	TX	WETLANDS WEST OF COPANO BAY	5/12/97

JS 44
(Rev. 07/89)

CIVIL COVER SHEET

97CV 37 B (W)

The JS-44 civil cover sheet and the information contained herein neither replace nor supplement the filing and service of process or other papers as required by law, except as provided by local rules of court. This form, approved by the Judicial Conference of the United States in September 1974, is required for the use of the Clerk of Court for the purpose of initiating the civil docket sheet. (SEE INSTRUCTIONS ON THE REVERSE OF THE FORM.)

I (a) PLAINTIFFS

United States

DEFENDANTS

Koch Industries, Inc.

RECEIVED

JUL 25 1997

U.S. ATTORNEY
N.D. OKLAHOMA(b) COUNTY OF RESIDENCE OF FIRST LISTED PLAINTIFF
(EXCEPT IN U.S. PLAINTIFF CASES)COUNTY OF RESIDENCE OF FIRST LISTED DEFENDANT
(IN U.S. PLAINTIFF CASES ONLY)

NOTE: IN LAND CONDEMNATION CASES, USE THE LOCATION OF THE TRACT OF LAND INVOLVED

(c) ATTORNEYS (FIRM NAME, ADDRESS, AND TELEPHONE NUMBER)

Angela O'Connell
U.S. Dept. of Justice P.O. Box 7411
Wash., D.C. 20044
(202) 514-5315

ATTORNEYS (IF KNOWN)

Robert McCully
Koch Industries, Inc.
P.O. Box 2256, Wichita, KS. 67201
(316) 828-8264

II. BASIS OF JURISDICTION

(PLACE AN X IN ONE BOX ONLY)

☒ 1 U.S. Government Plaintiff☐ 3 Federal Question
(U.S. Government Not a Party)☐ 2 U.S. Government Defendant☐ 4 Diversity
(Indicate Citizenship of Parties in Item III)

III. CITIZENSHIP OF PRINCIPAL PARTIES

(For Diversity Cases Only)

(PLACE AN X IN ONE BOX FOR PLAINTIFF AND ONE BOX FOR DEFENDANT)

Citizen of This State

PTF DEF

☐ 1 ☐ 1

Citizen of Another State

☐ 2 ☐ 2

Citizen or Subject of a Foreign Country

☐ 3 ☐ 3

Incorporated or Principal Place of Business in This State

PTF DEF

☐ 4 ☐ 4

Incorporated and Principal Place of Business in Another State

☐ 5 ☐ 5

Foreign Nation

☐ 6 ☐ 6

IV. CAUSE OF ACTION

(CITE THE U.S. CIVIL STATUTE UNDER WHICH YOU ARE FILING AND WRITE A BRIEF STATEMENT OF CAUSE)

DO NOT CITE JURISDICTIONAL STATUTES UNLESS DIVERSITY:

Civil action under the Clean Water & Oil Pollution Act of 1990, 33 U.S.C. Section 1251 et seq for civil penalties and injunctive relief in connection with spills of crude oil into waters of the U.S.

V. NATURE OF SUIT (PLACE AN X IN ONE BOX ONLY)

CONTRACT	TORTS	FORFEITURE/PENALTY	BANKRUPTCY	OTHER STATUTES
<input type="checkbox"/> 110 Insurance <input type="checkbox"/> 120 Marine <input type="checkbox"/> 130 Miner Act <input type="checkbox"/> 140 Negotiable Instrument <input type="checkbox"/> 150 Recovery of Overpayment & Enforcement of Judgment <input type="checkbox"/> 151 Medicare Act <input type="checkbox"/> 152 Recovery of Detained Student Loans (Excl. Veterans) <input type="checkbox"/> 153 Recovery of Overpayment of Veterans Benefits <input type="checkbox"/> 160 Stockholders Suits <input type="checkbox"/> 190 Other Contract <input type="checkbox"/> 195 Contract Product Liability	PERSONAL INJURY <input type="checkbox"/> 310 Airplane <input type="checkbox"/> 315 Airplane Product Liability <input type="checkbox"/> 320 Assault Libel & Slander <input type="checkbox"/> 330 Federal Employers Liability <input type="checkbox"/> 340 Marine <input type="checkbox"/> 345 Marine Product Liability <input type="checkbox"/> 350 Motor Vehicle <input type="checkbox"/> 355 Motor Vehicle Product Liability <input type="checkbox"/> 360 Other Personal Injury PERSONAL INJURY <input type="checkbox"/> 362 Personal Injury - Med Malpractice <input type="checkbox"/> 365 Personal Injury - Product Liability <input type="checkbox"/> 368 Asbestos Personal Injury Product Liability PERSONAL PROPERTY <input type="checkbox"/> 370 Other Fraud <input type="checkbox"/> 371 Truth in Lending <input type="checkbox"/> 380 Other Personal Property Damage <input type="checkbox"/> 385 Property Damage Product Liability	<input type="checkbox"/> 610 Agriculture <input type="checkbox"/> 620 Other Food & Drug <input type="checkbox"/> 625 Drug Related Seizure of Property 21 USC 881 <input type="checkbox"/> 630 Labor Laws <input type="checkbox"/> 640 R R & Truck <input type="checkbox"/> 650 Airline Regs <input type="checkbox"/> 660 Occupational Safety/Health <input type="checkbox"/> 690 Other LABOR <input type="checkbox"/> 710 Fair Labor Standards Act <input type="checkbox"/> 720 Labor/Mgmt Relations <input type="checkbox"/> 730 Labor/Mgmt Reporting & Disclosure Act <input type="checkbox"/> 740 Railway Labor Act <input type="checkbox"/> 790 Other Labor Litigation <input type="checkbox"/> 791 Emp'l Ret. Inc. Security Act	<input type="checkbox"/> 422 Appeal 28 USC 158 <input type="checkbox"/> 423 Withdrawal 28 USC 157 PROPERTY RIGHTS <input type="checkbox"/> 820 Copyrights <input type="checkbox"/> 830 Patent <input type="checkbox"/> 840 Trademark SOCIAL SECURITY <input type="checkbox"/> 861 HIA (1395f) <input type="checkbox"/> 862 Black Lung (923) <input type="checkbox"/> 863 DIWC/DIWW (405(g)) <input type="checkbox"/> 864 SSID Title XVI <input type="checkbox"/> 865 RSI (405(g)) FEDERAL TAX SUITS <input type="checkbox"/> 870 Taxes (U.S. Plaintiff or Defendant) <input type="checkbox"/> 871 IRS - Third Party 26 USC 7609	<input type="checkbox"/> 400 State Reapportionment <input type="checkbox"/> 410 Antitrust <input type="checkbox"/> 430 Banks and Banking <input type="checkbox"/> 450 Commerce/ICC Rates/etc <input type="checkbox"/> 460 Deportation <input type="checkbox"/> 470 Racketeer Influenced and Corrupt Organizations <input type="checkbox"/> 510 Selective Service <input type="checkbox"/> 550 Securities/Commodities/Exchange <input type="checkbox"/> 575 Customer Challenge 12 USC 3410 <input type="checkbox"/> 591 Agricultural Acts <input type="checkbox"/> 592 Economic Stabilization Act <input type="checkbox"/> 593 Environmental Matters <input type="checkbox"/> 594 Energy Allocation Act <input type="checkbox"/> 595 Freedom of Information Act <input type="checkbox"/> 900 Appeal of Fee Determination Under Equal Access to Justice <input type="checkbox"/> 950 Constitutionality of State Statutes <input type="checkbox"/> 990 Other Statutory Actions
REAL PROPERTY <input type="checkbox"/> 210 Land Condemnation <input type="checkbox"/> 220 Foreclosure <input type="checkbox"/> 230 Rent Lease & Ejectment <input type="checkbox"/> 240 Torts to Land <input type="checkbox"/> 245 Tort Product Liability <input type="checkbox"/> 290 All Other Real Property	CIVIL RIGHTS <input type="checkbox"/> 441 Voting <input type="checkbox"/> 442 Employment Housing Accommodations <input type="checkbox"/> 443 Welfare <input type="checkbox"/> 444 Other Civil Rights	PRISONER PETITIONS <input type="checkbox"/> 510 Motions to vacate Sentence Habeas Corpus <input type="checkbox"/> 530 General <input type="checkbox"/> 535 Death Penalty <input type="checkbox"/> 540 Mandamus & Other <input type="checkbox"/> 550 Other		

VI. ORIGIN

(PLACE AN X IN ONE BOX ONLY)

☒ 1 Original Proceeding☐ 2 Removed from State Court☐ 3 Remanded from Appellate Court☐ 4 Reinstated or Reopened

Transferred from another district (specify)

☐ 5 Multidistrict Litigation

Appeal to District Judge from Magistrate Judgment

VII. REQUESTED IN COMPLAINT:

CHECK IF THIS IS A CLASS ACTION UNDER F.R.C.P. 23

DEMAND \$

Check YES only if demanded in complaint:

JURY DEMAND: ☐ YES ☐ NO

VIII. RELATED CASE(S) (See instructions) IF ANY U.S. v. Koch *

JUDGE Kern

DOCKET NUMBER 91-C-763-B

DATE

SIGNATURE OF ATTORNEY OF RECORD

UNITED STATES DISTRICT COURT

* Related in that both cases involve Koch's failure to properly account for quantities of oil discharged or gathered from its crude oil lines.. Document universe is similar.

FPI-LEX3/91

43

**IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION**

UNITED STATES OF AMERICA,

Plaintiff,

and

THE STATE OF TEXAS,

Plaintiff/Intervenor,

V.

KOCH INDUSTRIES, INC. (a/k/a KOCH
OIL COMPANY); KOCH GATHERING
SYSTEMS, INC.; KOCH GATEWAY
PIPELINE COMPANY (successor to
UNITED GAS PIPE LINE COMPANY);
KOCH REFINING COMPANY; KOCH
SERVICE, INC.; KOCH MATERIALS
COMPANY; CHASE PIPELINE
COMPANY; BOW PIPE LINE COMPANY,
INC.; and CITRONELLE PIPELINE
COMPANY, INC.,

Defendants.

UNITED STATES COURTS
SOUTHERN DISTRICT OF TEXAS
FILED

FEB 11 1997

Michael N. Milby, Clerk of Court

CIVIL ACTION NO. H 95-1118

**INTERVENOR STATE OF TEXAS'
FIRST ORIGINAL COMPLAINT**

The State of Texas ("the State" or "Texas"), by the authority of the Attorney General of the State and through the undersigned attorneys, acting at the request of the Texas General Land Office ("TGLO"), files this Complaint and alleges as follows:

I. INTRODUCTION

1. This is a civil action brought pursuant to the Clean Water Act ("CWA"), 33 U.S.C. Section 1251 *et seq.*, as amended by the Oil Pollution Act of 1990 ("OPA"), Pub. L. 101-380, 104 Stat. 484, seeking injunctive relief, civil penalties, and recovery of oil pollution

response costs incurred as a result of the discharge of crude oil and petroleum products into navigable waters or adjoining shorelines of the United States and of Texas.

II. JURISDICTION, VENUE AND NOTICE

2. This Court has jurisdiction over this action under 28 U.S.C. Sections 1331, 1345, 1355 and 1395(a); CWA Sections 309(b) and 311(b)(7)(E) (33 U.S.C. §§ 1319(b) and 1321(b)(7)(E)), and OPA Sections 1002 and 1017(b) (33 U.S.C. §§ 2702, and 2717(b)).

3. Authority of the United States to bring this action is vested in the Department of Justice by 28 U.S.C. Sections 516 and 519 and 33 U.S.C. Section 1366.

4. Texas has intervened as a plaintiff by leave of Court pursuant to Federal Rule of Civil Procedure 24.

5. Venue is proper in the Southern District of Texas pursuant to 28 U.S.C. Sections 1391 and 1395(a); CWA Section 309(b) and 311(b)(7)(E) (33 U.S.C. §§ 1319(b) and 1321(b)(7)(E)), inasmuch as it is the judicial district in which each defendant does business or has consented to personal jurisdiction.

III. DEFENDANTS

6. Defendant, Koch Industries, Inc., a/k/a Koch Oil Co., is a Kansas corporation with its principal place of business in Houston, Texas.

7. Koch Industries, Inc., a/k/a Koch Oil Co., is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

8. Defendant, Koch Gathering Systems, Inc., is a Kansas corporation with its principal place of business in Houston, Texas.

9. Koch Gathering Systems, Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

10. Defendant, Koch Gateway Pipeline Co., is a Delaware corporation with its principal place of business in Houston, Texas.

11. Koch Gateway Pipeline Co. is the successor in interest to United Gas Pipeline Co.

12. Koch Gateway Pipeline Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

13. Defendant, Koch Refining Co., is a Delaware corporation with its principal place of business in Corpus Christi, Texas.

14. Koch Refining Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

15. Defendant, Koch Service, Inc., is a Kansas corporation that conducts business in Texas.

16. Koch Service, Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

17. Defendant, Koch Materials Co., is a Delaware corporation that conducts business in Texas.

18. Koch Materials Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

19. Defendant, Chase Pipeline Co., is a Kansas corporation that has consented to personal jurisdiction in Texas.

20. Chase Pipeline Co. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

21. Defendant, Bow Pipe Line Co., Inc., is an Oklahoma corporation that has consented to personal jurisdiction in Texas.

22. Bow Pipe Line Co., Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

23. Defendant, Citronelle Pipeline Co., Inc., is a Kansas corporation whose parent corporation, Koch Gathering Systems, Inc., conducts business in Texas.

24. Citronelle Pipeline Co., Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of CWA Section 311(a)(6), (10) and (11) (33 U.S.C. § 1321(a)(6), (10) and (11)) and is a person within the meaning of CWA Sections 311(a)(7) and 502(5) (33 U.S.C. §§ 1321(a)(7) and 1362(5)).

V. POSITION OF THE STATE OF TEXAS

25. Texas is the home and site of operation for several of the defendants. Many defendants own and operate facilities for the gathering and transportation of crude oil and natural gas within the boundaries of the State. The defendants' onshore and offshore facilities, underground pipelines, and refinery operations cover substantial territory within the State. Several of the defendants have made Texas their principal place of business.

26. Pursuant to Section 11.021 of the Texas Water Code, the State owns many of the resources that are at issue in this case, including Nueces Bay and surrounding coastal waters.

27. Texas also acts as a regulator and guardian of the health of millions of citizens of the State. In this role, Texas monitors and regulates water quality through a number of state agencies and under the jurisdiction of several state statutes. This monitoring and regulation affects the operations of the defendants that have given rise to the acts made the basis of this lawsuit.

28. Texas is charged with promoting industry in the State.

29. The violations that are at issue in this case have adversely affected the property, resources, industry, and citizens of the State. Texas has compelling interests in the defendants' current and future conduct within its borders.

V. THE CWA REGULATORY SCHEME FOR DISCHARGES OF OIL

A. Prohibition of Oil Discharges

30. CWA Section 301(a) (33 U.S.C. § 1311(a)) prohibits, except as otherwise authorized, the discharge of any pollutant, including oil, by any person. CWA Section 502(12) (33 U.S.C. § 1362(12)) defines "discharge of a pollutant" to include "any addition of any

pollutant to navigable waters from any point source." Oil is a pollutant within the meaning of CWA Section 502(6) (33 U.S.C. § 1362(6)).

31. CWA Section 311(b)(3) (33 U.S.C. § 1321(b)(3)) prohibits the discharge of oil into or upon the navigable waters of the United States and adjoining shorelines in such quantities as the President determines may be harmful to the public health or welfare or environment of the United States.

32. Pursuant to CWA Section 311(b)(4) (33 U.S.C. § 1321(b)(4)), the President, through a delegation to EPA, Executive Order No. 11735, 38 Federal Register 21243 (Aug. 7, 1973), has determined by regulation that the quantities of oil that may be harmful to the public health or welfare or environment of the United States include discharges of oil that, *inter alia*, cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines. 40 C.F.R. § 110.3.

B. Injunctive Relief

33. CWA Section 309(b) (33 U.S.C. § 1319(b)) authorizes EPA to commence a civil action for appropriate relief, including a permanent or temporary injunction, for any violation for which the EPA Administrator is authorized to issue a compliance order under CWA Section 309(a).

34. CWA Section 309(a) (33 U.S.C. § 1319(a)) authorized, *inter alia*, the issuance of compliance orders for discharges of pollutants prohibited under CWA Section 301(a) (33 U.S.C. § 1311(a)).

C. Civil Penalties

35. With respect to the discharges of oil alleged in Schedule A to this Complaint, which occurred prior to August 18, 1990, CWA Section 309(d) (33 U.S.C. § 1319(d)) provides, *inter alia*, that:

Any person who violates section 1311 [CWA Section 301] . . . shall be subject to a civil penalty not to exceed \$25,000 per day for each violation. [Bracketed material supplied.]

36. With respect to the discharges of oil alleged in Schedule A of this Complaint which occurred after August 18, 1990, CWA Section 311(b)(7) (33 U.S.C. § 1321(b)(7)) as amended by OPA, provides that:

Any person who is the owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged in violation of . . . [CWA Section 311(b)(3)], shall be subject to a civil penalty in an amount up to \$25,000 per day of violation or an amount up to \$1,000 per barrel of oil or unit of reportable quantity of hazardous substances discharged. [Bracketed material supplied.]

VI. FACTS GIVING RISE TO LIABILITY

37. The named defendants (collectively "Koch") own and operate underground crude oil pipelines and other onshore and offshore facilities in Texas, as well as Louisiana, Oklahoma, Kansas, Missouri, and Alabama.

38. On numerous occasions in the past five years, the defendants' pipelines and onshore and offshore facilities in Texas and the other named states have ruptured, causing oil and/or hazardous substances to spill into the environment and into the waters of the State and the United States or the adjoining shorelines. These ruptures and spills are continuing. Appendix A to the Complaint of the United States of America, which is attached hereto and incorporated herein for all purposes, lists the date, location, affected waterway, and - if reported - the National Response Center report number of each spill.

VII. CLAIMS FOR RELIEF

A. First Claim: Injunctive Relief

39. Paragraphs 1 through 38 are realleged and incorporated by reference.

40. Defendants' discharge of oil and/or hazardous substances, into or upon the navigable waters of the United States or adjoining shorelines in such quantities as have been determined to be harmful to the public health or welfare or environment of the United States and the State violate CWA Section 311(b)(3) (33 U.S.C. § 1321(b)(3)) and CWA Section 301 (33 U.S.C. § 1311(a)) and subjects defendants to injunctive relief pursuant to CWA Section 309(b) (33 U.S.C. § 1319(b)). Unless restrained by this Court, defendants will continue to discharge oil into the waters of the United States and the State in violation of the CWA and OPA.

B. Second Claim: Civil Penalties

41. Paragraphs 1 through 38 are realleged and incorporated by reference.

42. Defendants' discharges of oil as alleged herein, which occurred prior to August 18, 1990, violate CWA Sections 301(a) and 311(b)(3) (33 U.S.C. §§ 1311(a) and 1321(b)(3)) and, pursuant to CWA Section 309(d) (33 U.S.C. § 1319(d)), subjects defendants to a civil penalty not to exceed \$25,000 per day for each violation.

43. Defendants' discharges of oil and/or hazardous substances as alleged herein, which occurred after August 18, 1990, violate CWA Sections 301(a) and 311(b)(3) (33 U.S.C. §§ 1311(a) and 1321(b)(3)) and, pursuant to CWA Section 311(b)(7)(A) (33 U.S.C. § 1321(b)(7)(A)), subjects defendants to a civil penalty of up to \$1,000 per barrel of oil discharged.

44. CWA Section 309(b) (33 U.S.C. § 1319(b)) authorizes the commencement of a civil action for appropriate relief, including a permanent or temporary injunction. Unless

restrained by this Court, defendants will continue to discharge oil in violation of the CWA and OPA, to the detriment of the property, resources, industry, and citizens of Texas.

PRAYER FOR RELIEF

WHEREFORE, plaintiff, the State of Texas, respectfully requests that this Court enter judgment against the defendants for:


- a. Such injunctive relief pursuant to CWA Section 309(b) as may be necessary to prevent future releases and protect and restore the waters of the United States and the State of Texas; and
- b. Impose civil penalties on defendants of up to \$25,000 per day for each discharge of oil occurring prior to August 18, 1990, for violations of CWA Section 301(a) and impose civil penalties on defendants of up to \$1,000 per barrel of oil discharged in violation of CWA Section 311(b)(3) for all other spills alleged in the Complaint and all spills that occur or continue after the filing of this complaint, to be shared among the plaintiffs;
- c. Enter an Order requiring Koch to 1) report all spills of oil into waters of the United States to the National Response Center and 2) to accurately report the quantity of each spill.
- d. Such other relief to which the State may be entitled.

Respectfully submitted,

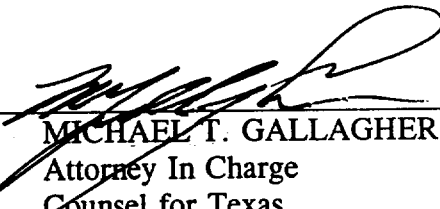
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ATTORNEYS FOR PLAINTIFF/INTERVENOR

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing Complaint of the State of Texas has been sent via U.S. Mail, certified and return receipt requested, on the ____ day of _____, 1997, to the following attorneys of record:

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1425 New York Avenue, Room 13015
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II. JURISDICTION, VENUE AND NOTICE

2. This Court has jurisdiction over this action under 28 U.S.C. §§ 1331, 1345, 1355 and 1395(a); Sections 309(b) and 311(b)(7)(E) of the CWA, 33 U.S.C. §§ 1319(b) and 1321(b)(7)(E), and Sections 1002 and 1017(b) of OPA, 33 U.S.C. §§ 2702 and 2717(b).

3. Authority to bring this action is vested in the United States Department of Justice by 28 U.S.C. §§ 516 and 519 and 33 U.S.C. § 1366.

4. Venue is proper in the Northern District of Oklahoma pursuant to 28 U.S.C. §§ 1391 and 1395(a); Section 309(b) and 311(b)(7)(E) of the CWA, 33 U.S.C. §§ 1319 (b) and 1321 (b)(7)(E), inasmuch as it is the judicial district in which each defendant does business.

5. Texas has moved to intervene as a plaintiff by leave of Court, as a matter of right, pursuant to Federal Rule of Civil Procedure 24(a) and Section 505 of the CWA. Texas also brings pendent claims pursuant to 28 U.S.C. §1367(a).

III. DEFENDANTS

6. Defendant, Koch Industries, Inc., is a Kansas corporation that conducts business in Oklahoma.

7. Koch Industries, Inc., is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11), and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

8. Defendant, Koch Pipeline Co., L.P. is a Delaware limited partnership that conducts business in Oklahoma.

9. Koch Pipeline Co., L.P. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. §

1321(a)(6), (10) and (11), and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

10. Defendant, Koch Gathering Systems, Inc., is a Kansas corporation that conducts business in Oklahoma.

11. Koch Gathering Systems, Inc. is an "owner/operator" of an "onshore facility" and an "offshore facility" within the meaning of Section 311(a)(6), (10) and (11) of the CWA, 33 U.S.C. § 1321(a)(6), (10) and (11), and is a person within the meaning of Sections 311(a)(7) and 502(5) of the CWA, 33 U.S.C. §§ 1321(a)(7) and 1362(5).

12. Koch Gathering Systems, Inc. merged into Koch Pipeline Co., L.P. in August, 1995.

IV. POSITION OF THE STATE OF TEXAS

13. Texas is the home and site of operation for several of the defendants. Many defendants own and operate facilities for the gathering and transportation of crude oil and natural gas within the boundaries of the State. The defendants' onshore and offshore facilities, underground pipelines, and refinery operations cover substantial territory within the State. All of the defendants do business in the State of Texas.

14. Pursuant to Section 11.021 of the Texas Water Code, the State owns many of the resources that are at issue in this case.

15. Texas also acts as a regulator and guardian of the health of millions of citizens of the State. In this role, Texas monitors and regulates water quality through a number of state agencies and under the jurisdiction of several state statutes. This monitoring and regulation affects the operations of the defendants that have given rise to the acts made the basis of this lawsuit.

16. Texas is charged with promoting industry in the State.

17. The violations that are at issue in this case have adversely affected the property, resources, industry, and citizens of the State. Texas has compelling interests in the defendants' current and future conduct within its borders.

V. THE CWA REGULATORY SCHEME FOR DISCHARGES OF OIL

A. Prohibition of Oil Discharges

18. Section 301(a) of the CWA, 33 U.S.C. § 1311(a), prohibits, except as otherwise authorized, the discharge of any pollutant, including oil, by any person. Section 502(12) of the CWA, 33 U.S.C. § 1362(12), defines "discharge of a pollutant" to include "any addition of any pollutant to navigable waters from any point source." Oil is a pollutant within the meaning of Section 502(6), 33 U.S.C. § 1362(6).

19. Section 311(b)(3) of the CWA, 33 U.S.C. § 1321(b)(3), prohibits the discharge of oil into or upon the navigable waters of the United States and adjoining shorelines in such quantities as the President determines may be harmful to the public health or welfare or environment of the United States.

20. Pursuant to Section 311(b)(4) of the CWA, 33 U.S.C. § 1321(b)(4), the President, through a delegation to EPA, Executive Order No. 11735, 38 Fed. Reg. 21243 (Aug. 7, 1973), has determined by regulation that the quantities of oil that may be harmful to the public health or welfare or environment of the United States include discharges of oil that, among other things, cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines. 40 C.F.R. § 110.3.

B. Injunctive Relief

21. Section 309(b) of the CWA, 33 U.S.C. § 1319(b), authorizes EPA to commence a civil action for appropriate relief, including a permanent or temporary injunction, for any violation for which the EPA Administrator is authorized to issue a compliance order under Section 309(a).

22. Section 309(a) of the CWA, 33 U.S.C. § 1319(a), authorizes, among other things, the issuance of compliance orders for discharges of pollutants prohibited under Section 301(a), 33 U.S.C. § 1311(a).

C. Civil Penalties

23. With respect to the discharges of oil alleged in Schedule 1 to this Amended Complaint, Section 309(d) of the CWA, 33 U.S.C. § 1319(d), provides, among other things, that:

Any person who violates section 1311 [Section 301] . . . shall be subject to a civil penalty not to exceed \$25,000 per day for each violation.

24. With respect to the discharge of oil alleged in Schedule 1 to this Amended Complaint, Section 311(b)(7) of the CWA, 33 U.S.C. § 1321(b)(7), as amended by OPA, provides that:

Any person who is the owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged in violation of ... [Section 311(b)(3) of the CWA], shall be subject to a civil penalty in an amount up to \$25,000 per day of violation or an amount up to \$1,000 per barrel of oil or unit of reportable quantity of hazardous substances discharged.¹

25. With respect to the discharge of oil alleged in Schedule 1 to this Amended Complaint, Section 311 (b)(7)(D) of the CWA, 33 U.S.C. § 1321(b)(7)(D), as amended by OPA provides that:

In any case in which a violation of ... [Section 311(b)(3)] was the result of gross negligence or willful misconduct of a person...the person shall be subject to a civil penalty of not less than \$100,000, and not more than \$3,000 per barrel of oil or unit of reportable quantity of hazardous substance discharged.

¹ The statutory penalty amounts are periodically amended for inflation as mandated by the Debt Collection Improvement Act of 1996. Currently, the maximum civil penalty for oil spills under this provision is \$1,100 per barrel. The alternative daily maximum has been increased to \$27,500. 62 Fed. Reg. 35038-35041 (June 27, 1997).

26. With respect to the discharge of oil alleged in Schedule 1 to this Amended Complaint,

Section 91.003(a) of the Texas Natural Resources Code provides that:

(a) In addition to other authority specifically granted to the commission under this chapter, the commission may enforce this chapter or any rule, order, or permit of the commission adopted under this chapter in the manner and subject to the conditions provided in Chapters 81 and 85 of this code, including the authority to seek and obtain civil penalties and injunctive relief as provided by those chapters.

27. With respect to the discharge of oil alleged in Schedule 1 to this Amended Complaint,

Section 85.381 of the Texas Natural Resource Code provides that:

(a) In addition to being subject to any forfeiture provided by law and to any penalty imposed by the commission for contempt for violation of its rules or orders, any person who violates the provisions of Sections 85.045 and 85.046 of this code, Title 102, Revised Civil Statutes of Texas, 1925, as amended, including provisions of this code formerly included in that title, or any rule or order of the commission promulgated under those laws is subject to a penalty of not more than:

(1) \$10,000 when the provision, rule, or order pertains to safety or the prevention or control of pollution; or

(2) \$1,000 when the provision, rule, or order does not pertain to safety or the prevention or control of pollution.

(b) The applicable maximum penalty may be assessed for each and every day of violation and for each and every act of violation.

Acts 1977, 65th Leg., p. 2528, ch. 871, art. I, § 1, eff. Sept. 1, 1977.
Amended by Acts 1983, 68th Leg., p. 5251, ch. 967, § 1, eff. Sept. 1, 1983.

VI. FACTS GIVING RISE TO LIABILITY

28. The named defendants (collectively "Koch") own and operate underground crude oil pipelines and other onshore facilities throughout the states of Texas, Louisiana, Oklahoma and Kansas.

29. On numerous occasions in the past five years, (including but not limited to those spills specifically alleged in Schedule 1 to this Amended Complaint) the defendants' pipelines and onshore facilities in the named states have ruptured, causing oil and/or hazardous substances to spill into the environment and into the waters of the United States or the adjoining shorelines. These ruptures and spills are continuing. Schedule 1 to this Amended Complaint lists the date, location (including county and state), affected waterway, and the National Response Center report number of each spill for which civil penalties and injunctive relief are sought pursuant to this action.

30. Koch operates crude oil pipelines in the State of Texas subject to the jurisdiction of the Railroad Commission of Texas. As part of Koch's operation of those pipelines Koch has violated 16 Texas Administrative Code Section 3.8(b) by causing or allowing the pollution of surface or subsurface water of the state as those terms are defined in 16 Texas Administrative Code Section 3.8(a)(28) and (29). In addition, as a result of the operation of its crude oil pipelines, Koch also has violated 16 Texas Administrative Code Section 3.8(d) by disposing of oil and gas wastes that are subject to the regulations of the Railroad Commission of Texas without obtaining a permit or other legal authorization. For Koch's violations of 16 Texas Administrative Code Sections 3.8(b) and 3.8(d), the State requests civil penalties in the amount of up to \$10,000 per violation per day in accordance with Texas Natural Resources Code Section 91.003 and Chapter 85.

VII. CLAIMS FOR RELIEF

A. First Claim: Injunctive Relief

31. Paragraphs 1 through 29 are realleged and incorporated by reference.

32. Defendants' discharges of oil and/or hazardous substances, into or upon the navigable waters of the United States or adjoining shorelines in such quantities as have been determined to be harmful to the public health or welfare or environment of the United States and the State violate Section 311(b)(3) of the CWA, 33 U.S.C. § 1321(b)(3) and Section 301, 33 U.S.C. § 1311(a), and subject defendants to injunctive relief pursuant to Section 309(b), 33 U.S.C. § 1319(b). Unless restrained by this Court, defendants will continue to discharge oil into the waters of the United States and the State in violation of the CWA and OPA.

B. Second Claim: Civil Penalties

33. Paragraphs 1 through 29 are realleged and incorporated by reference.

34. Defendants' discharges of oil and/or hazardous substances as alleged herein violate Sections 301(a) and 311(b)(3) of the CWA, 33 U.S.C. §§ 1311(a) and 1321(b)(3), and, pursuant to Section 311(b)(7)(A), 33 U.S.C. § 1321(b)(7)(A), subject defendants to a civil penalty of up to \$1,000 per barrel of oil discharged.

35. Defendants' discharges of oil and/or hazardous substances as alleged herein which were the result of defendants' gross negligence or willful misconduct and which occurred in violation of Sections 301(a) and 311(b)(3) of the CWA, 33 U.S.C. §§ 1311(a) and 1321(b)(3), and, pursuant to Section 311(b)(7)(D) of the CWA, 33 U.S.C. 1321(b)(7)(D), subject defendants to a civil penalty of not less than \$100,000 and up to \$3,000 per barrel of oil discharged.

36. Section 309(b), 33 U.S.C. § 1319(b), authorizes the commencement of a civil action for appropriate relief, including a permanent or temporary injunction. Unless restrained by this Court,

defendants will continue to discharge oil in violation of the CWA and OPA, to the detriment of the property, resources, industry, and citizens of Texas.

C. Third Claim: State Penalties

37. Paragraphs 1 through 29 are realleged and incorporated by reference.

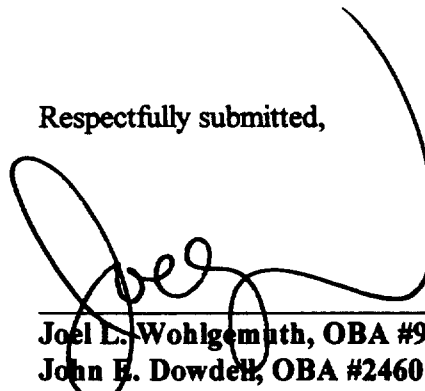
38. Defendants' discharges of oil and/or hazardous substances as alleged herein violate the Texas Natural Resource Code, Section 91.003 et seq., and, pursuant to Section 85.381, subject the Defendants' to a State penalty of up to \$10,000.00 per violation.

PRAYER FOR RELIEF

WHEREFORE, plaintiff-intervenor, the State of Texas, respectfully requests that this Court enter judgment against the defendants:

- a. For such injunctive relief pursuant to Section 309(b) as may be necessary to prevent future releases and protect and restore the waters of the United States and the State of Texas;
- b. Imposing civil penalties on defendants of up to \$1,000 per barrel of oil discharged in violation of CWA Section 311(b)(3) for all spills alleged in the Amended Complaint and all spills that occur or continue after the filing of this Amended Complaint;
- c. Imposing civil penalties on defendants of not less than \$100,000 and up to \$3,000 per barrel of oil discharged in violation of Section 311(b)(3) that were the result of defendants' gross negligence or willful misconduct;
- d. Ordering Koch (1) to report all spills of oil into waters of the United States to the National Response Center and (2) to accurately report the quantity of each spill;
- e. Imposing state penalties on defendants of not less than \$1,000 and up to \$10,000 for each violation of the Texas Natural Resources Code which may be shown herein; and
- f. For such other relief to which the State may be entitled.

Respectfully submitted,



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The State of Texas

CERTIFICATE OF MAILING

I hereby certify that on this 26th day of January, 1998 a true and correct copy of the above and foregoing instrument was mailed by United States Mail, to:

Robert J. McCully
KOCH INDUSTRIES, INC.
P.O. Box 2256
4111 E. 37th Street North
Wichita, Kansas 67201

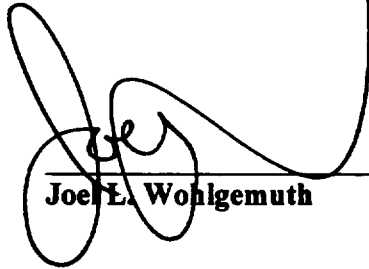
James L. Kincaid
CROWE & DUNLEVY
500 Kennedy Building
321 South Boston
Tulsa, Oklahoma 74103-3313

Richard W. Hosking
Thomas J. Smith
KIRKPATRICK & LOCKHART, L.L.P.
1500 Oliver Building
Pittsburgh, Pennsylvania 15222

Angela F. O'Connell
U.S. DEPARTMENT OF JUSTICE
Environment and Natural Resources Division
Environmental Enforcement Section
P.O. Box 7611
Ben Franklin Station
1425 New York Avenue, N.W., Room 12021
Washington, D.C. 20044

Phillip Pinnell
Assistant U.S. Attorney
U.S. ATTORNEY'S OFFICE
3600 U.S. Courthouse
333 West Fourth Street
Tulsa, Oklahoma 74103

Gordon Speights Young
Special Assistant United States Attorney
Northern District of Oklahoma
P.O. Box 61129
Houston, Texas 77208-1129



Joel L. Wohlgemuth

SCHEDULE I

SPILL #	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
1	335179	KGS	SEC.-NE 6, R-19W, T-17S, 7 MILES WEST OF LACROSSE	RUSH	KS	BIG TIMBER CREEK	4/7/96
2	289247	KGS	GROSS TETE, LA	IBERVILLE	LA	UPPER GRAND RIVER	4/29/95
3	358527	KGS	5 MILES NORTH OF HOMINY	OSAGE	OK	HOMINY CREEK	8/27/96
4	307676	KGS	SEC.-27, R-5W, T-1S	STEPHENS	OK	WILD HORSE CREEK > LAKE TEXOMA	9/16/95
5	354295	KGS	SEC.-17, R-5W, T-2N	STEPHENS	OK	UNNAMED CREEK LEADING TO RUSH CREEK	7/31/96
6	298408	KGS	CLEVELAND	OSAGE	OK	UNNAMED CREEK	7/5/95
7	348927	KGS	SEC.-35, R-5W, T-3N	GRADY	OK	UNNAMED CREEK AND STOCK TANK- PART OF THE RUSH CREEK WATERSHED PROJECT	6/25/96
8	144252	KGS	SEC.-32, R-10E, T-22N	OSAGE	OK	WILDHORSE CREEK	11/10/92
9	308214	KP	SEC.-6, R-2W, T-8S	LOVE	OK	TRIBUTARY TO RED RIVER	9/21/95
10	308425	KGS	SEC.-17, R-10E, T-24N	OSAGE	OK	BIRCH CREEK LEADING TO BIRCH LAKE	9/22/95
11	293852	KGS	SIVELLSBEND, GAINESVILLE, TX	COOKE DUNCAN	TX OK	RED RIVER	6/1/95
12	360289	KP	LAT-33 44 01 N; LONG-96 40 59 W 5.7 MILES WEST OF SHERMAN	GRAYSON	TX	UNNAMED CREEK	9/8/96
13	351075	KGS	LAT-32 57 01 N; LONG-99 09 43 W 9 MILES SOUTHWEST OF WOODSON	SHACKELFORD	TX	SHIRLEY CREEK RANCH	7/9/96

SPILL #	NRC #	CO.	LOCATION	COUNTY	ST.	WATERWAY AFFECTED	DATE
14	314836	KGS	COUNTY ROAD 128 IN RURAL AREA 8 MILES SOUTH OF CALDWELL	BURLESON	TX	PIN OAK CREEK	11/20/95
15	386988	KP	EDMOND J. FORD RANCH, WOODSBORO	REFUGIO	TX	WETLANDS WEST OF COPANO BAY	5/12/97

45



Rimkus Consulting Group, Inc.
Eight Greenway Plaza, Suite 500
Houston, Texas 77046
(713) 621-3550 Telephone
(713) 623-4357 Facsimile

EXPERT OPINION OF

MR. THOMAS J. KOCUREK, P.E.
MR. ERNEST M. HONIG, JR. PHD.
MR. PHILIP R. WATTERS, M.B.A., P.E.

Style: United States and the State of Texas v. Koch Industries, Inc., et al
Court: United States District Court for the Southern District Of Texas,
Houston Division
Date: January 4, 1999

SUMMARY OF OPINION

Rimkus Consulting Group, Inc. was retained by the United States Department of Justice (D.O.J.) and the State of Texas to examine the causes of each spill and to determine whether Koch acted prudently in the conduct of its pipeline activities. The purpose of our study and examination was to determine the following:

- Whether Koch violated any of the provisions of the D.O.T. 49CFR195 regulations.
- Whether Koch violated any of the provisions of the American Society of Mechanical Engineers (ASME) B31.4 codes.
- Whether Koch violated any of the provisions of the National Association of Corrosion Engineers (N.A.C.E.) standards.

- Whether Koch violated any of the provisions of the American Petroleum Institute (A.P.I.) Recommended Practices which contributed to the cause of each spill.
- Whether Koch violated their company standards, recommended practices, operation, maintenance, and emergency procedures.

Our study and examination was also to analyze and issue an opinion on the following:

- Koch's Pipeline Leak History
- Koch's Leak Prevention Programs and Policies
- Koch's Pipeline Assessment Program
- Koch's Mapping and Records Documentation
- Koch's Pipeline Construction and Repair Procedures

CONCLUSIONS

Based on our study and examination of the relevant documents to date, we have formed the following conclusions.

1. Koch failed to operate the pipeline system in a reasonable and prudent manner.
2. The majority of Koch's pipeline spills were attributed to corrosion (both external and internal).
3. The percentage of pipeline spills due to corrosion in the lawsuit time period of 1990 to 1995 was comparable to Koch's 1989 leak cause analysis for the time period of 1988 to 1989 indicating a long-term corrosion problem within Koch's pipeline system and leak prevention program.
4. Koch's map documents and records do not meet the requirements of the Federal D.O.T. 49CFR195 Regulations, the ASME B31.4 Codes, and Koch's Operation Maintenance and Emergency Manual procedures.
5. Koch's Pipeline Assessment program indicated deficiencies in Koch's corrosion prevention, personnel training, pipeline depths, and over-pressure prevention within their pipeline systems.
6. Although Koch's total spill releases per year have decreased from the period of time between 1988 through 1996, the average volume quantity per spill release has increased over the same time period, indicating leaks are occurring in pipelines with higher flow volumes. Koch's total spill quantities

within their pipeline gathering system totaled over 277,000 barrels (11,634,000 gallons) between the same time period of 1988 through 1996.

7. Koch failed to adhere to the D.O.T. 49CFR195 regulations, ASME B31.4 codes, Koch standards, and NACE RP-01-69 and RP-07-72 standards regarding external corrosion control for a number of their pipeline spills. A total itemization of the spill locations affected by Koch's failure to adhere to the regulations and codes cannot be completed until receipt of all Koch discovery responses and deposition statements.
8. Koch failed to adhere to the D.O.T. 49CFR195 regulations and the ASME B31.4 codes in providing adequate ground cover over their pipelines to prevent damage by third-parties. A total itemization of the spill locations affected by Koch's failure to provide adequate ground cover cannot be completed until receipt of all Koch discovery responses and deposition statements.
9. Koch failed to provide adequate dike protection to contain spill discharges at their asphalt facility in Missouri.
10. Koch failed to monitor the rate of internal corrosion of their pipelines with an adequate coupon monitoring system. A total itemization of the spill locations affected by Koch's failure to monitor the rate of internal corrosion cannot be completed until receipt of all Koch discovery responses and deposition statements.
11. Koch's leak repairs to their gathering system were inadequate per API standards and ASME B31.4 codes in that the repairs failed to prevent additional spills at the same location on the same pipeline.
12. Koch's own internal Pipeline Assessment Program estimated costs totaling \$98 million to recondition their pipelines to industry standards reflects the inadequate condition of their pipeline system.
13. Koch failed in one instance to promptly detect the pipeline leak and to cease operations to minimize the spill quantity. An itemization of other spill locations affected by Koch's failure to promptly detect the pipeline leak and to minimize the spill quantity cannot be completed until receipt of all Koch discovery responses and deposition statements.
14. We believe that Koch was deficient in the adequacy of their pre-acquisition investigation of pipeline systems they acquired, on which the leaks described in the lawsuit occurred and is relevant to whether Koch acted prudently in the conduct of its pipeline operation. An opinion of Koch's pre-acquisition investigations cannot be completed until receipt of all Koch discovery responses and deposition statements.

DISCUSSION

A federal lawsuit was filed in 1995 by the United States of America (United States) against Koch Industries Inc. (Koch) and their subsidiaries for crude oil and petroleum product spills which occurred from Koch's pipeline systems and plant facilities. The pipeline spills involved in the lawsuit occurred from 1990 through 1995 and were located in the states of Texas, Oklahoma, Kansas, Louisiana, Alabama, and Missouri. The United States alleges that all the Koch spills outlined in the lawsuit entered navigable waters of the state, and as result, Koch was in violation of the provisions of the Clean Water Act of 1972 and of the Oil Pollution Act of 1990. The pipeline spills involved in the lawsuit occurred on both regulated Department of Transportation (D.O.T.) pipelines, as well as non-regulated pipelines. The plant facility spill occurred in Missouri from an asphalt plant owned by a Koch subsidiary.

In order to segregate our various studies and examinations which were performed to analyze the factors that contributed to the spills, the Discussion Section of this Report of Findings is itemized according to the following areas.

- Koch's Leak History
- Koch's Leak Prevention Programs
- Koch's Pipeline Assessment Programs
- Koch's Mapping and Record Documentation
- Koch's Pipeline Construction and Maintenance Repair Procedures
- Koch's Adherence to Federal, Industry and Internal Company Codes and Standards
- Koch's Asphalt Plant Facility
- Koch's Dock Facilities
- Koch's Nueces Bay, Texas Spill

Koch's Leak History

In 1989, Koch established a leak prevention team to analyze the causes of leaks within all the divisions of their pipeline system. A result of the leak cause analysis that was performed by Koch's leak prevention team was a pie-chart outlining the causes of all leaks. This chart was issued in 1989 and covered all leak caused on a percentage basis for the years of 1988 to 1989. The chart (see Attachment A) indicated that 81 percent of all Koch Gathering System leaks were caused by corrosion. Sixty-nine percent (69%) of the total leaks were

caused by external corrosion; twelve percent (12%) of the total leaks were caused by internal corrosion; twelve percent (12%) of the total leaks were caused by third party damage; and seven percent (7%) were caused by other reasons such as operator error, equipment failures, or acts of God (floods, lightning, etc.). In reviewing the Koch documents and evaluating the causes of the 312 leaks involved in the United States lawsuit, our analysis indicates that 61 percent of the leaks involved in the lawsuit were caused by corrosion (see Attachment B). The pipeline spills involved in the United States lawsuit occurred during the time period of 1990 to 1995.

As a result of our study, it was determined that Koch was aware of the extensive leaks that were caused by corrosion as far back as 1989, which ~~was~~ seven years prior to Koch's eventual Pipeline Assessment Program which was performed in 1996.

In analyzing the Koch documents, it was determined that although the amount of Koch spills were decreasing each year from 1989 to 1996 (see Attachment C), the average volume per spill release was increasing over the same time period from approximately 45 barrels each in 1988 to over 85 barrels each in 1994, 1995, and 1996 (see Attachment D). This indicates that leaks were occurring in pipelines with higher flow volumes.

In analyzing the Koch documents, it was determined that according to Koch documents, Koch's total spill quantities within their pipeline system totaled over 277,000 barrels (11,634,000 gallons) between the time period of 1988 to 1996. During the time period of 1990 to 1995 according to Koch documents, a total of 163,000 barrels (6,846,000 gallons) were spilled from Koch's pipeline system. The 312 spill quantity involved in the United States lawsuit totals over 54,035 barrels or 2,269,482 gallons.

In summary, the governments are seeking relief on only 33 percent of the spill quantities by Koch for the time period 1990 to 1995. However, the total quantities spilled represent a clearer picture of Koch's overall leak history and associated leak prevention problems.

Koch's Leak Prevention Program

As stated earlier, Koch management established a leak prevention team in 1989. In addition to analyzing the causes of Koch's pipeline leaks, the Koch leak prevention team established four phases of remediation recommendations. These four phases consisted of Risk Assessment, Economic Evaluation, Pipe Protection, and Future Leak Prevention. Under the risk assessment, the Koch leak prevention team recommended that each Koch pipeline division should form a team to systematically evaluate all lines in their division. The pipeline evaluation was to be based on the following criteria:

- Leak history of the line
- Condition of the line
- Historical cleanup or liability costs
- Potential for extraordinary environmental and/or landowner damage, and for safety liability
- Potential for unfavorable media coverage
- Operating pressure of line and the expected trend (Will the pressure trend higher or lower in the future?)
- Other operating characteristics of the line (erratic operation, paraffin buildup, etc.)

The pipeline leak prevention team recommendations were not implemented in 1989. The Koch leak prevention team was discontinued in 1990 and was not reorganized until 1992 when meetings were held again. The Risk Assessment Program and evaluations which the leak prevention team had recommended in 1989 were not performed until 1996 which was over seven years and over 235,687 barrels of spills later between the years of 1989 and 1996.

It is our opinion that Koch acted unreasonably in not promptly allowing the leak prevention team to perform in 1989 the Risk Assessment Program, the Economic Evaluations (Cost Analysis), Pipe Protection, and Future Leak Prevention Programs which was the first step in developing a program to prevent leaks.

Koch's Pipeline Risk Assessment Program

In 1996, Koch finally performed and completed a Risk Assessment Program of their pipeline systems. The pipeline Risk Assessment Program consisted of three parts as follows:

- An evaluation of each pipeline's operation, design integrity, corrosion prevention, leak impact, potential clean-up costs, and third-party notifications as well as developing recommendations to recondition their pipelines to industry standards.
- A cost evaluation of the monetary expenditures that Koch would be exposed to in order to recondition their pipeline to industry standards.
- An economic evaluation to determine whether each pipeline system evaluated should be reconditioned to industry standards, shut down, or sold.

Upon review of Koch's pipeline risk assessment documents, our analysis is that Koch had deficiencies in many areas, including corrosion prevention, personnel training, pipeline depths, and over-pressure prevention.

Koch's pipeline assessment scores were very low in comparison to the pipeline assessment scores that could be obtained, indicating the magnitude of the pipeline deficiencies.

The cost analysis portion of the Risk Assessment Program indicated that an expenditure of over \$98 million would have to be expended by Koch to recondition the pipelines to industry standards.

Although Koch has not produced the economic evaluation, which was part of the risk analysis, a large portion of Koch's pipeline system was sold in 1998.

It is our conclusion that an economic evaluation was performed by Koch and, as a result, many of the pipelines were sold rather than shutting them down or expending the costs to recondition the pipelines to industry standards.

It is also our conclusion that Koch's Pipeline Risk Assessment Program costs totaling \$98 million reflected the inadequate condition of their pipelines and pipeline systems which contributed to the pipeline spills.

Koch's Mapping and Record Documentation

In reviewing the mapping documents supplied by Koch, it is our opinion that many of Koch's maps do not adhere to either D.O.T. 49 CFR195 regulations or ASME B31.4 codes for non-D.O.T. regulation lines.

Many of the maps submitted by Koch did not include the following required items:

- The location of cathodic protection facilities
- The location of valves
- Pressure safety device locations

Many of the records and interrogatory responses by Koch did not address the following information:

- The diameter, grade, type, and nominal wall thickness of their pipelines.
- The maximum operating pressure of each pipeline.

It is our conclusion that the maps and interrogatory responses submitted by Koch indicates that Koch is deficient in the required maps and records to be maintained either by federal regulators or by code requirements.

Our analysis also concluded that Koch did not maintain an adequate mapping or record documentation as required by Koch's own company operation, maintenance, and emergency manuals. The failure to have an adequate mapping and record documentation can affect the emergency response period of time to shut a pipeline down in an emergency situation.

Koch's Pipeline Construction and Maintenance Repair Procedures

Our analysis of Koch's pipeline construction and maintenance repair procedures indicates many repairs of Koch's gathering system pipelines were made by the use of pipe clamps only. Pipe clamps are normally used as a temporary repair only. Koch used the pipe clamps as a permanent repair rather than evaluating, pressure testing, and replacing the pipe.

An example of this method of repair was spill number 232 in which over three pipe clamps were used to repair previous leaks due to external corrosion on the pipe over a period of less than six months. An external corrosion failure on the pipe later spilled over 85 barrels (3,570 gallons) into a creek before Koch finally replaced the pipeline at the creek location.

It is our opinion that Koch is not evaluating their leaks to determine the appropriate repairs required to prevent future spills.

Koch's Adherence To Federal, Industry and Internal Company Codes and Standards

Our analysis of whether Koch adheres to federal, industry, and internal company codes and standards indicates that there are deficiencies in their external and internal corrosion prevention programs, pipe covering requirements, and training programs. Koch's own pipeline risk assessment program in 1996 reflects these deficiencies in the same areas. These deficiencies indicate that Koch is not operating its pipeline system in a reasonable and prudent manner.

Deficiencies in code requirements included lack of maintaining a -.85 volt pipe to soil cathodic protection voltage for external corrosion prevention, lack of coupons to monitor the internal corrosion, lack of adequate pipe covering as required by code, lack of adequate maps and documents as required by code, and lack of adequate operator training.

The federal and industry codes and standards state that in implementing these codes and standards, safety is the basic consideration for the protection of the

general public and operating company personnel. Failure to adhere to the provisions of these codes and standards jeopardizes that basic consideration.

It is our opinion that the deficiencies outlined by our analysis and Koch's risk assessments contributed to the leaks. A final evaluation of Koch's adherence to the regulations, codes, and standards cannot be performed until receipt of all discovery responses and deposition statements are obtained.

Regulations, codes, and standards that involve Koch's pipeline system that have not been adhered to include the following:

A. Department of Transportation 49 CFR 195 Regulations

- 49CFR 195.404 - Failure to maintain adequate maps and records
- 49CFR 195.414 - Failure to maintain an adequate cathodic protection program
- 49CFR 195.416 - Failure to maintain an adequate external corrosion control program
- 49CFR 195.418 - Failure to maintain an adequate internal corrosion control program
- 49CFR 195.428 - Failure to maintain adequate over-pressure safety devices
- 49CFR 195.248 - Failure to maintain adequate cover over buried pipelines
- 49CFR 195.266 - Failure to maintain adequate construction

B. American Society of Mechanical Engineers (ASME)

B31.4 - Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols.

- ASME B31.4.436 - Failure to adequately inspect the pipelines
- ASME B31.4.450 - Failure to adhere to operation and maintenance procedures affecting safety
- ASME B31.4.451 - Failure to adhere to pipeline operation and maintenance procedures.
- ASME B31.4.452 - Failure to adhere to pump station, terminal, and tank farm operation and maintenance procedures
- ASME B31.4.453 - Failure to adequately maintain corrosion control of the pipelines
- ASME B31.4.456 - Failure to qualify a piping system for a higher operating pressure

- ASME B31.4.457 - Failure to properly abandon a piping system
- ASME B31.4.460 - Failure to maintain corrosion control (General)
- ASME B31.4.461 - Failure to maintain an adequate external corrosion control for buried or submerged pipelines
- ASME B31.4.462 - Failure to maintain an adequate internal corrosion control program
- ASME B31.4.463 - Failure to maintain an adequate external corrosion control program for pipelines exposed to the atmosphere
- ASME B31.4.464 - Failure to provide adequate corrective measures for corrosion
- ASME B31.4.465 - Failure to maintain adequate records

C. National Association of Corrosion Engineers (NACE) Standards

- NACE RP-01-69 - Failure to maintain an adequate control of external corrosion
- NACE RP-05-72- Failure to maintain an adequate design, installation, operation, and maintenance of groundbeds program

D. American Petroleum Institute (API) Recommended Practices

- API 653 - Failure to maintain an adequate tank inspection, repair, alteration, and reconstruction program
- API 1110 - Failure to maintain an adequate pressure testing program of liquid petroleum pipelines
- API 1118 - Failure to adequately train and qualify liquid pipeline controllers
- API 1119 - Failure to adequately train and qualify liquid pipeline operators
- API 1120 - Failure to adequately train liquid pipeline maintenance personnel
- API 2200 - Failure to adequately repair crude oil and product pipelines

E. Koch's Standards and Recommended Practices.

- KOG STD 103.001 - Failure to provide an adequate diking design and storage tank layout
- KTOS STD 1301.076 - Failure to provide an adequate operation of cathodic protection

- KOG RP 1302.076 - Failure to provide an adequate internal corrosion program in pipelines
- KOG RP 1108.078 - Failure to provide an adequate stray current interference testing program
- KTOS RP 1301.077 - Failure to provide an adequate close interval survey standard program
- KOG STD 1108.076 - Failure to provide an adequate pigging program
- KTOS RP 1304.001 - Failure to provide an adequate pipeline coating program to prevent corrosion
- Failure to adhere to Koch's Operations, Maintenance and Emergency Manual (Oklahoma Division)
- Failure to adhere to Koch's Operations, Maintenance and Emergency Manual (South Texas)
- Failure to adhere to Koch's Operations, Maintenance and Emergency Manual (South Cushing Division)
- Failure to adhere to Koch's Operating, Maintenance and Emergency Manual for North Cushing and Kansas

Koch's Asphalt Plant Facility

Our analysis of Koch's non-pipeline spill indicates that the asphalt plant facility did not have an adequate tank retention diking system to contain asphalt spills caused by a tank failure. Additional diking facilities were installed only after the failure occurred.

An adequate tank retention diking system is required by industry standards as well as Koch's own standards. Koch's failure to have an adequate dike retention system at the asphalt plant facility did not contribute to the cause of the spill but was the reason the asphalt product entered into the navigable waters.

Koch's Dock Facilities

Our analysis of Koch's Dock Facility spills indicate that the spills were due to a lack of operator training. The type of dock facility spills impacted by a lack of operator training included dock valves left open, over filling of barges, and open barge flanges during barge loading and unloading operations.

Koch's Nueces Bay, Texas, Spill

Koch failed to promptly detect the pipeline leak that occurred in October 1994 which spilled crude into Nueces Bay, Texas. Koch also failed to cease operation of the pipeline after the leak occurred to minimize the spill quantity. An itemization of other spill locations affected by Koch's failure to promptly detect

the leaks and to cease operation of the pipeline after the leak occurred to minimize the spill quantity cannot be completed until receipt of all Koch discovery responses and deposition statements.

BASIS OF REPORT

In conducting our study and examination of this case, we performed the following work:

1. Reviewed Koch's Pipeline Assessment Program.
2. Reviewed Koch's Leak Reports, National Response, Center Reports, and pipe repair correspondence for each spill.
3. Reviewed photographs of the spill sites.
4. Interviewed Koch personnel in Wichita, Kansas.
5. Reviewed Koch's pipeline maps and construction records.
6. Reviewed documents from Koch's Leak Response Team, Leak Prevention Team, and Zero Leak Team.
7. Reviewed Koch's Leak History database and documents.
8. Reviewed Koch's Corrosion database, Star database, Bass database and Crude Oil Assessment database information.
9. Reviewed Koch's Pipeline Standards and Recommended Practices documents.
10. Reviewed Koch's Operation, Maintenance and Emergency manuals.
11. Reviewed Koch's Interrogatory Responses received to date.
12. Reviewed pipeline metallurgical reports, inspection reports, pipe replacement reports and pipe abandonment reports submitted by Koch to date.
13. Reviewed Koch's Cathodic Protection, Pigging, Rectifier, Chemical/Injection, Close Interval Survey and Corrosion Prevention documents.
14. Reviewed Koch's SCADA system, alarm summaries and operational data.
15. Reviewed DOT 49 CFR 195, ASME B31.4, API, and NACE Industry Pipeline Regulations, Standards and Codes.
16. Reviewed Plaintiff's Requests for Production of Documents.

This report was prepared for the United States Department of Justice, Environmental Enforcement Division and the State of Texas. Our report is based on information made available to us at this time.

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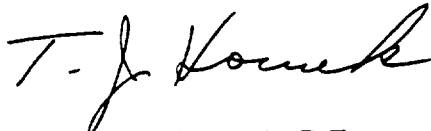
January 4, 1999

As additional information becomes available, our opinions and conclusions may change. We reserve the right to revise our opinions and conclusions and trust we will have the opportunity to supplement this report with a more detailed analysis once additional information becomes available.

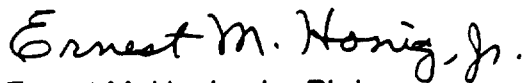
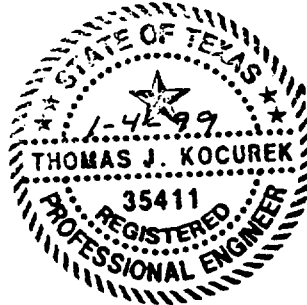
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Sincerely,

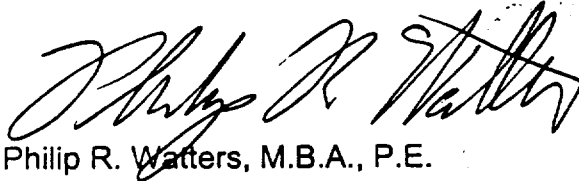
Rimkus Consulting Group, Inc.



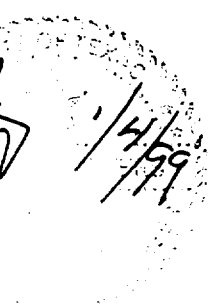
Thomas J. Kocurek, P.E.
Project Manager



Ernest M. Honig, Jr., Phd
Project Manager



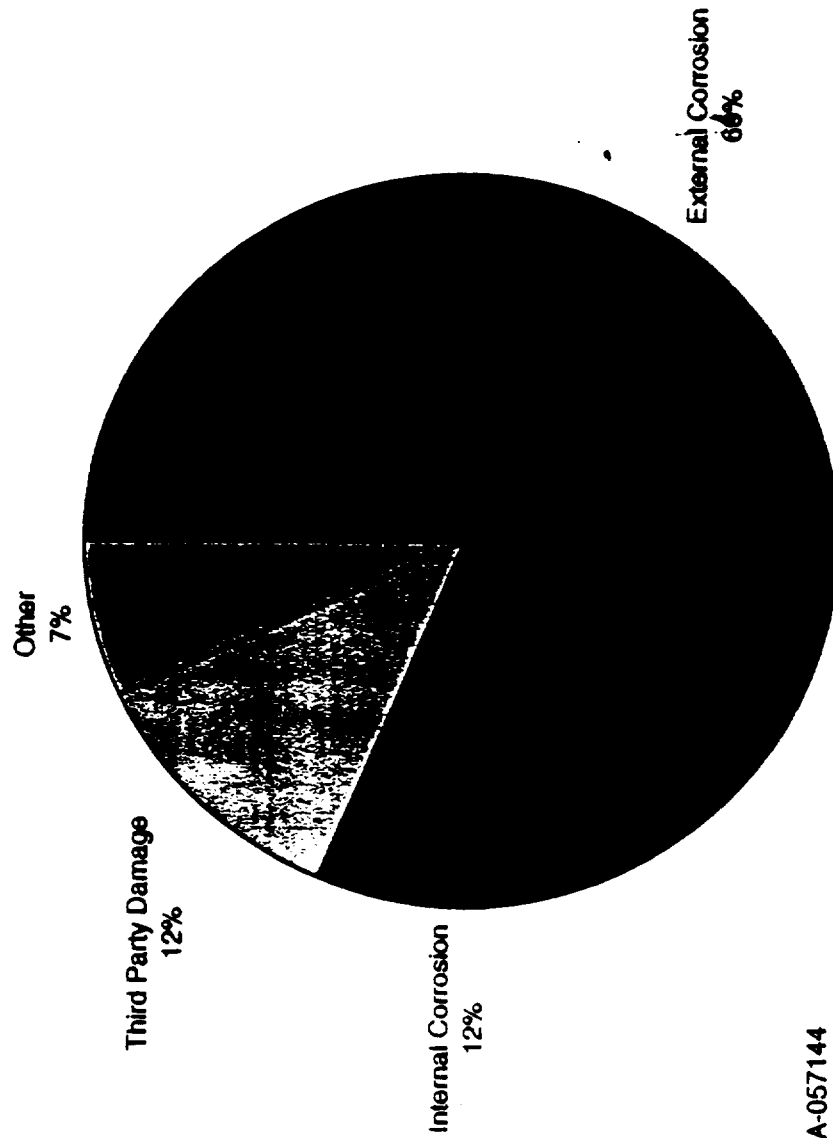
Philip R. Watters, M.B.A., P.E.
Senior Vice President



ATTACHMENT A

**KOCH GATHERING SYSTEMS
CAUSES OF LEAKS
1988 - 1989**

KGSI ALL DIVISIONS
Causes of Leaks
1988-1989

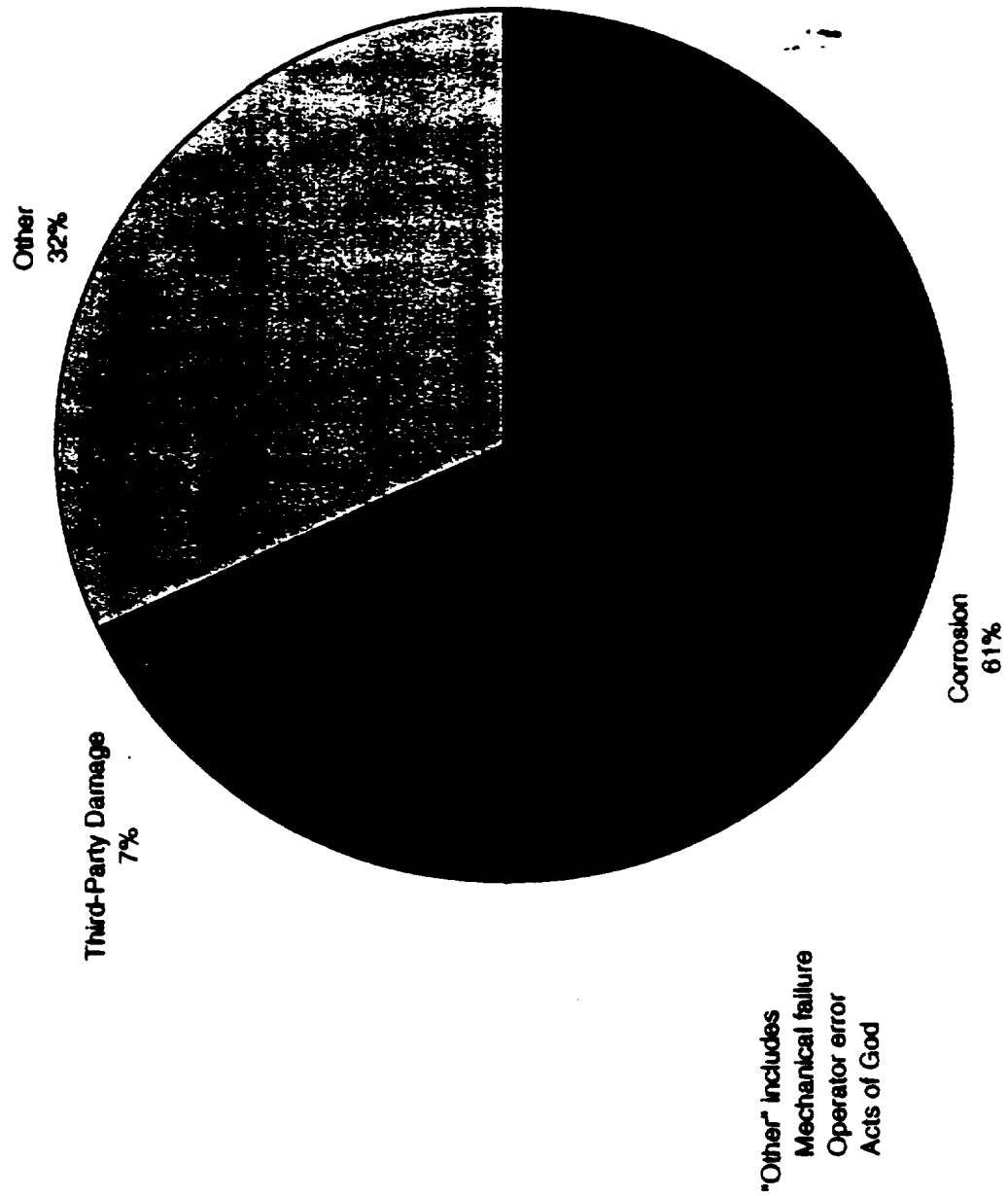


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ATTACHMENT B

**KOCH GATHERING SYSTEMS
CAUSES OF LEAKS
(ORIGINAL 312 SPILLS)
1990 - 1995**

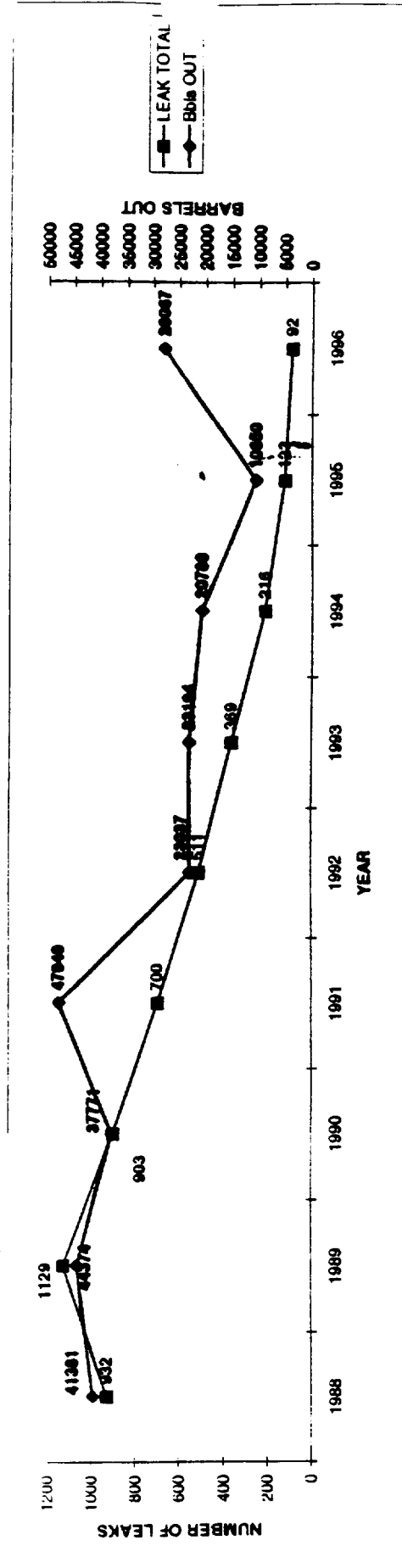
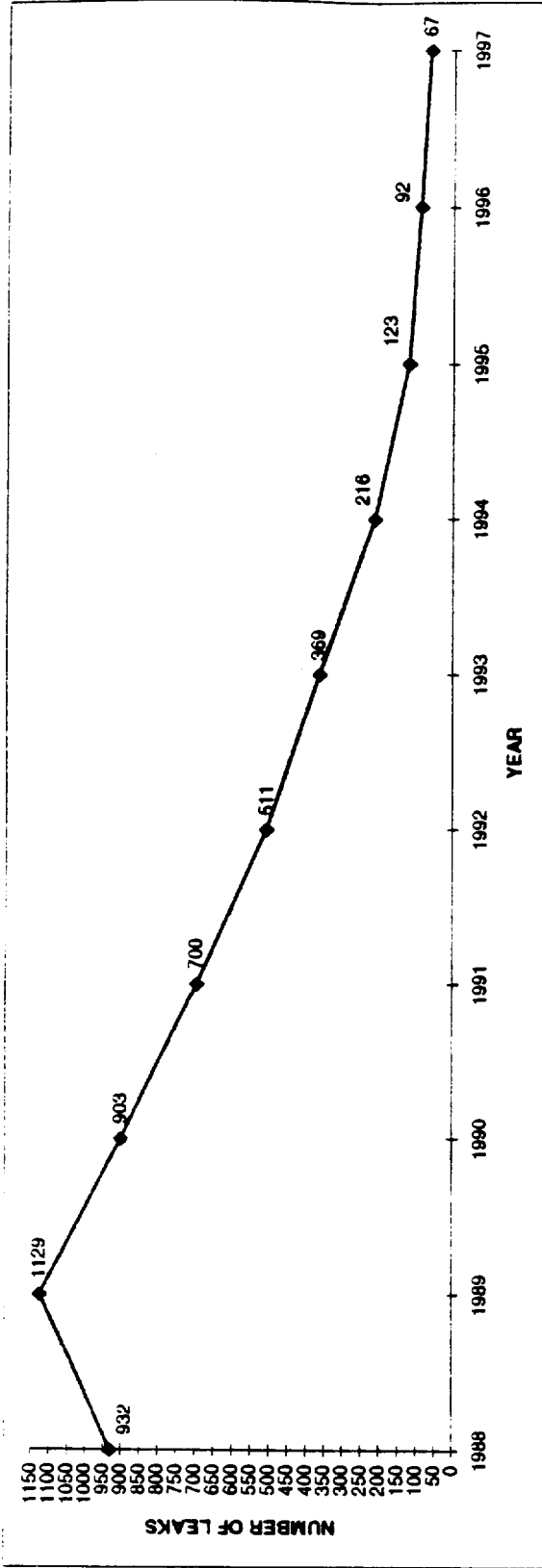
**Causes of Koch Spills
Original 312 Spills**



ATTACHMENT C

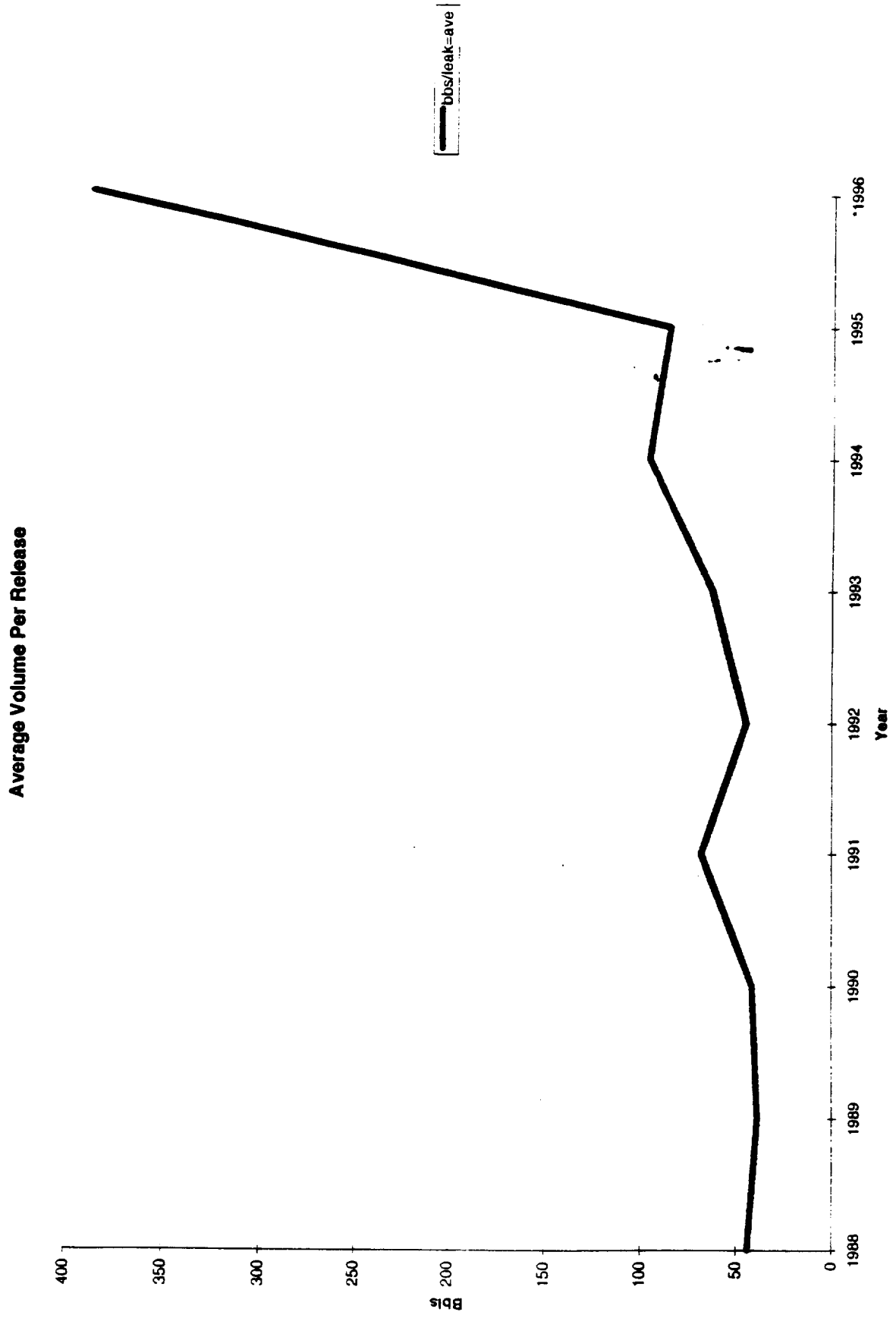
**LEAK HISTORY CHART
1988 - 1996**

Leak totals



ATTACHMENT D

**AVERAGE VOLUME PER SPILL
RELEASE CHART
1988 - 1996**



ATTACHMENT E

**CURRICULUM VITAE
AND TESTIMONY EXPERIENCE
OF
MR. THOMAS J. KOCUREK, P.E.**



**THOMAS J. KOCUREK, P.E.
PROJECT MANAGER**

Mr. Kocurek is a 1965 graduate of the University of New York at Farmingdale with an associate's degree in Construction Technology and a 1969 graduate of Texas Tech University with a bachelor's degree in Civil Engineering. He is also a registered professional engineer in the state of Texas.

Mr. Kocurek's professional experience includes both project and construction management responsibilities for the installation of refinery, chemical, pipeline, and gas plants facilities.

Mr. Kocurek's construction management background includes working as Manager of Construction in which he was the department head for an engineering and construction firm in charge of all construction projects. His project management background includes serving as Project Manager for an independent oil company in charge of all major capital refinery and piping projects. He has experience in engineering design, field construction supervision, and the development, negotiation, and implementation of engineering and construction contracts.

EDUCATION AND PROFESSIONAL ASSOCIATIONS

B.S. - Civil Engineering - Texas Tech University, 1969
A.A.S. - Construction Technology - University of New York at Farmingdale, 1965
Mobile Crane Management Certification
Mobile Crane & Rigging Certification
OSHA 40-Hour HAZWOPER Training
Registered Professional Engineer - Texas
Member - American Society of Civil Engineers (ASCE)

EMPLOYMENT HISTORY

1994 - Present	Rimkus Consulting Group, Inc.
1992 - 1994	LaGloria Oil & Gas (Contract)
1988 - 1992	Ventech Engineers, Inc.
1977 - 1988	Crown Central Petroleum Corporation
1976 - 1977	International Systems and Controls
1969 - 1976	The M. W. Kellogg Company

HOUSTON	DALLAS/FT. WORTH	SAN ANTONIO	CORPUS CHRISTI	
AUSTIN	NEW ORLEANS	ATLANTA	CHICAGO	TAMPA

THOMAS J. KOCUREK, P.E.

DETAILED PROFESSIONAL EXPERIENCE:

RIMKUS CONSULTING GROUP, INC.

1994 - PRESENT

Project Manager

Duties include construction accident and claim analysis, review of contractual documentation, and evaluation of contractor performance in the areas of engineering and construction. Provide consulting services in the areas of construction damage assessment in oil, chemical, pipelines and gas plant facilities. Provide consulting services in the areas of safety, maintenance, engineering, and construction litigation. Provide consulting services for major oil and chemical companies as well as government agencies.

LaGLORIA OIL & GAS

1992 - 1994

(A wholly owned subsidiary of Crown Central Petroleum)

Project Construction Manager (Contract)

Duties included all project and construction management of two Diesel Hydrotreater projects, reporting to the Vice President of Refining. Also supervised all engineering and construction personnel, and assisted in start-up operations.

VENTECH ENGINEERS, INC.

1988 - 1992

Manager Of Construction

Project construction responsibility for all contracts with various clients totaling between \$1 million and \$25 million, reporting to the Vice President of Operations. Duties included management of field personnel for each project, approval authority of all subcontracts, review of engineering schedules and material procurement documents for incorporation into the construction schedule, and representing the firm in all owner/Ventech construction staff meetings for each project.

CROWN CENTRAL PETROLEUM CORPORATION

1977 - 1988

Project Manager

Project responsibility for all major capital engineering and construction contracts, reporting to the Vice President of Refining. These projects consisted of the following:

- 22,000 BBL per day reformer
- 15 ton per day sulfur plant
- FCCU power recovery unit
- 1000 ton per day/calcliner expansion
- Calcliner waste heat boiler

THOMAS J. KOCUREK, P.E.

- 13,000 BBL per day coker
- Crude Unit Atmospheric Tower compressor facility
- Two LPG units and associated offsite projects
- Environmental RCRA facilities pipelines, and closures

Reviewed all monthly cost and progress reports issued by each engineering and construction contractor; issued monthly cost and budget reports to management; and reviewed with company officials potential problems of each project in the areas of engineering and construction contractual liabilities, cost, accounting, productivity, progress and quality control.

Also reviewed material control procedures and subcontracts of each engineering and construction contractor; coordinated all field construction with Crown Refinery maintenance and start-up operational personnel; supervised project engineering including process, mechanical, and electrical/instrumentation personnel; represented firm in all client/contractor staff meetings for each project.

INTERNATIONAL SYSTEMS AND CONTROLS

1976 - 1977

Operational Auditor

International Systems and Controls was a holding corporation owning subsidiaries engaged in engineering, manufacturing, training, and financial operations. Subsidiaries at that time: J.F. Pritchard (Kansas City); Stadler Hurter (Montreal and Iran); Sanderson & Porter (New York); Black, Sivals & Bryson (Houston); and Lang Engineering (Florida).

Inspected all construction and engineering projects of the subsidiaries—both domestic and foreign—ensuring that the cost control, progress reporting, accounting, and quality control conformed to corporate requirements in engineering and construction standards. Issued technical reports within the corporation that defined the results of each inspection, indicating problem areas, and submitting probable solutions or alternatives that could be applied to resolve the problem. Audited the subsidiaries by reviewing with their project management and project engineering personnel the activities, progress, or problems that existed regarding the engineering, purchasing, and construction of their projects.

THOMAS J. KOCUREK, P.E.

THE M. W. KELLOGG COMPANY

1969 - 1976

Construction Engineer

Duties consisted of all phases of construction dealing with the erection and inspection of large petroleum, chemical plant, and pipeline projects (both foreign and domestic). Supervised construction personnel, resolving any engineering problems that arose. Monitored cost factors for each week's work; developed construction procedures and methods for the purpose of revamping existing and operating facilities with a minimum of expense and shutdown time.

Developed and issued subcontract packages; established liaison between the field management engineering personnel on the jobsite with project and construction management within the home office; ensured that construction management was kept informed of all engineering developments affecting the schedule, cost, or quality control of each project.

TESTIMONY EXPERIENCE
THOMAS J. KOCUREK, P.E.
(Last Four Years)

Testimony Date: 1998
Cause No: CV197-017
Court: U.S. District Court - Southern Division of Georgia
Style of Case: Arcadian Fertilizer vs. M.P.W. Industrial

Testimony Date: 1998
Cause No: 97-07631
Court: District Court of Harris County
Style of Case: Pyramid Constructors vs. Harris County, Texas

Testimony Date: 1998
Cause No: D-153,998
Court: District Court of Jefferson County, Texas
Style of Case: Charles Crowson vs. Kansas City Southern Railway

Testimony Date: 1997
Cause No: 9648786
Court: District Court of Harris County, Texas
Style of Case: Estate of John Fitzgerald vs. Griffin Drilling

Testimony Date: 1997
Cause No: CV-96-RRA-2918-W
Court: District of Alabama, Western Division
Style of Case: Lollar vs. Hunt Refining Company

Testimony Date: 1997
Cause No: 96-37053
Court: District Court of Harris County, Texas
Style of Case: Larry Parker vs. Hoechst Celanese Corporation

Testimony Date: 1997
Cause No: 1:97CV00095
Court: U. S. District Court, Beaumont Division
Style of Case: Mid-Continent Casualty vs. Chevron Pipeline Co.

Testimony Date: 1996
Cause No: 1:95CV899
Court: U.S. District Court, Beaumont Division
Style of Case: Sanford Fant vs. Chevron Pipeline Co.

Testimony Date: 1996
Cause No: 94-049501
Court: District Court of Harris County, Texas
Style of Case: Ian Harris vs. Flow Components

Testimony Date: 1996
Cause No: 94-019137
Court: District Court of Harris County
Style of Case: RYCO Industries vs. Gaskey Construction

Testimony Date: 1995
Cause No: H-94-1438
Court: U.S. District Court, Houston, Texas
Style of Case: Jaro Jones vs. Texas Petrochemicals Corp.

ATTACHMENT F

**CURRICULUM VITAE
AND TESTIMONY EXPERIENCE
OF**

MR. ERNEST M. HONIG, JR., PHD.



**ERNEST M. HONIG, JR., Ph.D.
PROJECT MANAGER**

Dr. Honig is a graduate of the University of Arizona with a master's degree and Ph.D. in physical metallurgy, as well as a bachelor's degree in mechanical engineering from Rice University in Houston. He has broad experience in analysis and innovative solution of problems with metallurgical materials and processes.

Dr. Honig's functional areas of expertise include nonmagnetic/corrosion-resistant alloy selection, welding, failure analysis of metals and ceramics, quality assurance, nondestructive testing, and analysis of management problems in metallurgical systems processing. Application industries include oil and gas production and refining, petrochemical, aerospace, automotive, electronics, energy and power systems, and military ordnance.

In addition to his hands-on experience, Dr. Honig has authored several articles featured in metallurgical journals.

EDUCATION AND PROFESSIONAL ASSOCIATIONS

Ph.D. Physical Metallurgy, Physics minor; University of Arizona, Tucson, Arizona; 1973.

MS Physical Metallurgy; University of Arizona, Tucson, Arizona; 1967.

BS Mechanical Engineering; Rice University, Houston, Texas; 1964.

BA; Rice University, Houston, Texas; 1963.

Member: American Society for Metals (ASM)
American Society of Mechanical Engineers (ASME)
National Association of Corrosion Engineers (NACE)
American Welding Society (AWS)
The Metallurgical Society of AIME (TMS)
Sigma Xi

EMPLOYMENT HISTORY

1997 - Present	Rimkus Consulting Group, Inc.
1995 - 1997	National Association of Corrosion Engineers (NACE)
1991 - 1995	Cypress Consulting
1985 - 1991	Anadrill/Schlumberger
1978 - 1985	Getty Oil Company/Texaco Inc.
1977 - 1978	U.S. Army Tank-Automotive Command
1973 - 1977	U.S. Army Construction Engineering Research Laboratory(CERL)

HOUSTON

DALLAS/FT. WORTH

SAN ANTONIO

CORPUS CHRISTI

AUSTIN

NEW ORLEANS

ATLANTA

CHICAGO

TAMPA

ERNEST M. HONIG, JR., Ph.D.

DETAILED PROFESSIONAL EXPERIENCE:

RIMKUS CONSULTING GROUP, INC.

1997 - PRESENT

Project Manager

Provide technical consulting services to law firms, insurance companies, and corporations. Responsibilities include mechanical and metallurgical analyses; investigation of industrial accidents; analysis of fires and explosions; reconstruction of vehicular accidents; and study of man/machine interactions.

NATIONAL ASSOCIATION OF CORROSION ENGINEERS (NACE)

1995 - 1997

Technical Editor

Worked with NACE technical committees to develop new standards and revise existing ones for corrosion reduction in industrial environments.

CYPRESS CONSULTING

1991 - 1995

Owner/Metallurgical Consultant

Determined cause of metallurgical failure of industrial components.

ANADRILL/SCHLUMBERGER

1985 - 1991

Engineering Specialist - Physical Metallurgy

Advised management of engineering, manufacturing, and quality assurance on choice of metals, ceramics, and processes for measurement-while-drilling (MWD) hardware, in particular: drill collars, pressure housings, and weight-on-bit subs. Adapted and specified processes to include welding, heat treating, surface hardening, and platings and coatings for corrosion/wear resistance. Investigated deterioration of ceramic face seals by erosion-corrosion. Eliminated cracking in electron-beam welded joints on Inconel 718 to Nitronic 50 by using stress-relief groove with improved welding parameters. Compiled a computerized materials database for engineers and designers. Determined that the cause of wire bond failure in a microelectronic accelerometer was wire fatigue due to inappropriate manufacturing procedure. Problem was corrected by new procedures.

GETTY OIL COMPANY/ TEXACO INC.

1978 - 1985

Physical Metallurgist

Advised management of properties and applications of metals and ceramics for petrochemical industries. Conducted metallurgical analysis of field equipment failures. Specialized in selection of corrosion-resistant alloys for tubulars and valves for deep, hot, corrosive oil/gas wells. Investigated sour-brine corrosion of cement lining of oil field piping.

ERNEST M. HONIG, JR., Ph.D.

Taught selection of corrosion-resistant metals and ceramics in courses for production operations staff. Eliminated gas well shut-in, due to CO₂ corrosion of alloy steel production tubing, by using Alloy 2205 corrosion-resistant tubing. Conducted corrosion testing program simulating production conditions and found Alloy 2205 most economical among surviving high alloy grades. Gas well corrosion could not be chemically inhibited due to sand production. Solved oilfield corrosion problems in British North Sea and in Kuwait, on-site.

U.S. ARMY TANK-AUTOMOTIVE COMMAND

1977 - 1978

Supervisory Materials Engineer

Directed \$1.7 million program in military automotive R&D for advanced manufacturing methods of metallic components. Programs included computer-aided design/manufacturing and laser welding to reduce costs and increase system reliability. Supervised 14 materials engineers, welders, and clerical personnel. Proposed, obtained, and budgeted funding; performed near/long-term planning.

**U.S. ARMY CONSTRUCTION ENGINEERING
RESEARCH LABORATORY (CERL)**

1973 - 1977

Senior Metallurgist (1975-1977) / Metallurgist (1973-1975)

Managed and conducted programs in fossil energy research applied to military facilities. Included programs on solar energy, central total energy plants, flue gas dust control, coal utilization, and refuse-derived fuel. Supervised five engineers. Conducted and managed fracture mechanical analysis of flaws in steel weldments. Eliminated routine rework of shielding weld defects for "hardened" missile communications facilities by determining flaw size criteria experimentally. Published ten technical reports.

TESTIMONY EXPERIENCE
ERNEST M. HONIG, JR., PH.D.

Deposed:

Testimony Date:	September 1997
Cause Number:	BC-064046
Court:	Los Angeles Superior Court, CA
Style of Case:	Douglas Oil Company of California, Conoco, Inc., and Continental Oil Company v. Allianz Insurance Co. et al
Attorney:	P. Casey
Law Firm:	McElroy, Deutsch & Mulvaney

Testimony Date:	February 1998
Cause Number:	96-61561
Court:	215 th Dist. Ct., Harris County, TX
Style of Case:	Tomcat Exploration, Excelsior Exploration & Comite Gas Plant v. TGX Corporation
Attorney:	G. Mathews
Law Firm:	Winstead, Sechrest & Minick

Testimony Date:	December 1998
Cause Number:	97-12874
Court:	215 th Dist. Ct., Harris County, TX
Style of Case:	Riviera II Council of Co-Owners v. Jalayer & Assocs., Inc. and McBride Ratcliff and Assocs.
Attorney:	J. Janecek
Law Firm:	Butler & Hailey

ATTACHMENT G

**CURRICULUM VITAE
AND TESTIMONY EXPERIENCE
OF
MR. PHILIP R. WATTERS MBA, P.E.**



**PHILIP R. WATTERS, M.B.A., P.E.
SENIOR VICE PRESIDENT**

Mr. Watters is a 1969 engineering graduate of Michigan Technological University and 1972 graduate of the University of Houston Business School. His professional experience has been in the petrochemicals, refining, offshore oil and gas exploration and natural gas processing industries. He is knowledgeable in economics, market research, supply/demand and price forecasting, process and mechanical engineering design, environmental assessments, process economics and optimization and technology evaluations. He has owned and managed consulting, refined product trading and venture capital firms. He has prepared and delivered numerous papers, expert reports, and depositions during litigation proceedings.

Mr. Watters' principal areas of expertise include business interruption and economic evaluations, process technology audits, manufacturing cost analysis, process design, project evaluations, product contract negotiations, piping system design and acquisition studies. Mr. Watters has performed investigations of pipeline economic losses, industrial accidents, fires, explosions, wrongful death economic losses, toxic/hazardous waste evaluations, including determination of cause, origin, extent, and severity of environmental contamination, product contamination, subrogations and product liability determinations. His experience also includes evaluating and forecasting the impact of government environmental regulations on energy product demands, pricing and profitability.

EDUCATION AND PROFESSIONAL ASSOCIATIONS

M.B.A. - University of Houston
B.S. - Chemical Engineering - Michigan Technological University
Registered Professional Engineer - Texas
Completed 40-Hour OSHA Hazardous Waste Operations and Emergency Response (HAZWOPER) Course
Member: American Institute of Chemical Engineers
Chemical Marketing Research Association
Houston LPG Committee
Southwest Chemical Association

EMPLOYMENT HISTORY

1989 - Present	Rimkus Consulting Group, Inc.
1986 - 1989	Resource Planning Consultants, A Bonner & Moore Company
1981 - 1986	Resource Planning Consultants, Inc.
1975 - 1981	Pace Consultants, Inc.
1973 - 1975	Advanced Management Systems, Inc.
1969 - 1973	Exxon Chemical Company

HOUSTON	DALLAS/FT. WORTH	SAN ANTONIO	CORPUS CHRISTI
AUSTIN	NEW ORLEANS	ATLANTA	CHICAGO

DETAILED PROFESSIONAL EXPERIENCE:

RIMKUS CONSULTING GROUP, INC.

1989 - PRESENT

Senior Vice President

Provide litigation support for attorneys and corporate counsels; claims investigations and evaluations for insurance companies; assistance in negotiation and settling contract disputes; courtroom demonstrative evidence, including computer animations and simulations; and forecasting the supply/demand and pricing of energy related products.

Consulting projects have included economic evaluations, of business interruption and property damage claims, linear programming optimization models and pro forma economic models of refineries and petrochemical plants, determination of cause, origin, extent, and severity of environmental contamination, employee theft and dishonesty claims, wrongful death economic determination, fire/explosion and accident reconstructions, heat and material balances of refineries and petrochemical plants, historical margin audits, assisting attorneys in data requests and deposition preparation for opposing technical experts, forecasting environmental regulations impact on automobile fuels demand, and auditing hazardous chemical process operations and environmental clean-up plans.

RESOURCE PLANNING CONSULTANTS, A BONNER & MOORE CO.

1986 - 1989

President (1988 - 1989)

Responsible for marketing, planning, and project coordination of multi-client consulting services for domestic and international clients in natural gas, natural gas liquids, and petrochemical feedstocks.

Conducted market research studies to identify joint venture opportunities, linear programming simulations of olefin plant operations, regional natural gas and natural gas liquids supply/demand and pricing, and expert testimony regarding gas processing contract litigation.

Vice President (1986 - 1988)

Responsible for new business development in single client consulting area and coordination of merger with the Bonner & Moore Associates, Inc. organization.

Project activities included studies of helium contracting practices, screening study for a MTBE project, competitive helium manufacturing cost analysis, start-up of a West Coast natural gas and natural gas liquids multi-client study, and ongoing participation in natural gas liquids multi-client consulting practice.

HOUSTON

DALLAS/FT. WORTH

SAN ANTONIO

CORPUS CHRISTI

AUSTIN

NEW ORLEANS

ATLANTA

CHICAGO

RESOURCE PLANNING CONSULTANTS, INC.

1981 - 1986

Vice President/Director

Director and co-founder of energy consulting firm specializing in single client and multi-client services to the petrochemical, natural gas, natural gas liquids and refining industries. Responsible for marketing, new business development, employee hiring and administration.

Consulting project work encompassed analysis of fuel switching impact on natural gas pipelines, evaluating alkylate feedstock stream values, propane pipeline acquisition analysis, NGL raw mix pipeline expansion analysis, market forecasts for methyl ethyl ketone and isopropyl alcohol, evaluation of vacuum gas oil streams, marketing of gas plant condensate, worldwide helium supply/demand and pricing studies, survey of ethane contracting practices, market research of database requirements in exploration/production industries, business entry strategic analysis, methanol feasibility study for plant relocation to the Middle East, and analyzing impacts of government natural gas pricing decontrol on petrochemicals.

PACE CONSULTANTS, INC.

1975 - 1981

Manager of Market Analysis (1979 - 1981)

Responsibilities included the supervision of market analysis studies and the development of price forecasting services in petrochemicals, natural gas, and refined products. Developed a consulting practice in the oil and gas exploration/production industry focusing on offshore drilling activity forecasts.

Consulting activities included industrial market research, supply/demand and price forecasting model development for petrochemicals and refined products, and utility fuels purchasing strategy development.

Consultant/Senior Consultant (1975 - 1979)

Participated in and managed consulting assignments encompassing supply, demand and pricing analysis.

Project work included: gasohol feasibility study, propylene purchasing study, expert testimony preparation for refined products contract lawsuit, analysis of gasoline lead phase-down on premium gasoline, government studies of California crude oil transportation alternatives, heavy crude oil upgrading studies, competitive technology/manufacturing costs of plastic resins, refinery acquisition studies, retail gasoline marketing acquisition studies, siting of diesel truck stops, and olefins manufacturing cost evaluations.

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ATLANTA

CHICAGO

ADVANCED MANAGEMENT SYSTEMS, INC.

1973 - 1975

Consultant/Senior Consultant

Supervised staff of natural gas and crude oil piping designers; designed offshore natural gas gathering pipeline system and compressor installations; acquisition studies and management of office buildings and apartments; market research of retail gasoline marketing trends; profit improvement studies for retail gasoline marketing; and, development of computerized corporate planning models.

EXXON CHEMICAL COMPANY

1969 - 1973

Technical Service Engineer

In-charge of providing technical service and project engineering in polypropylene, isobutylene extraction and butyl rubber manufacture. Engineering responsibilities included waste water treating facilities and minimization of liquid wastes and air-borne emissions.

Project responsible for coordinating plant test runs of new resins, start-up of new production technologies, design/construction/start-up of waste water recovery unit, screening studies for new technologies, preparing operating standards; participated in quality improvement teams and environmental audits.

HOUSTON

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SAN ANTONIO

CORPUS CHRISTI

AUSTIN

NEW ORLEANS

ATLANTA

CHICAGO

TESTIMONY EXPERIENCE
PHILIP R. WATTERS, P.E., M.B.A.

Testimony Date: July 5 and 6, 1994
Cause: CV-88-0351982S
Court: Superior Court, Hartford, CT
Style: Reichhold Chemicals, Inc. vs. Hartford, et al.
Attorney: Sean Joyce

Testimony Date: January 11, 1995
Cause: H-91-3158
Court: United States District Court for the Southern District of Texas, Houston Division
Style: Cooper Industries, Inc., in its own right and as successor-in-interest to Arrow Hart Corporation, Crouse-Hinds Company and Kirsch Company, and Kirsch Company in its own right vs. Liberty Mutual Insurance Company, et al.
Attorney: Anthony Cox

Testimony Date: April 4, 1995
Cause Number: 94-016590
Court: 215th District Court of Harris County, TX
Style of Case: Jetfill, Inc. et al. vs. Graphic Utilities, Inc. et al.
Attorney: John Lee

TESTIMONY EXPERIENCE
PHILIP R. WATTERS, P.E., M.B.A.

Testimony Date: August 1 and 2, 1995
Cause Number: CV-91-1023
Court: U.S. District Court for Western District
of Louisiana, Shreveport Division
Style of Case: Racetrac Petroleum, Inc. vs. Ida
Gasoline Company, Inc., Sartomer
Company Inc., Mount Hawley
Insurance Company, and American
International Insurance Company
Attorney: James Wise, Mark Clemer

Testimony Date: September 3 and 4, 1997
Cause Number: 944196
Court: Superior Court of the State of
California, In and For the County of
San Francisco
Style of Case: Varian Associates, Inc. vs. AETNA
Casualty and Surety Company
Attorney: Bryan Wilson

Testimony Date: October 28, 1997
Cause Number: BC 064046
Court: Superior Court of Los Angeles
Style of Case: Douglas Oil Company of California, et
al. (Conoco) vs. Allianz Insurance
Company
Attorney: Guy Roy

Testimony Date: December 4, 1997
Cause Number: 96-166-CIV-ORL-19
Court: United States District Court for the
Middle District of Florida Orlando
Division
Style of Case: Harris Corporation vs. Travelers
Indemnity Company
Attorney: David Bolton, Robert Lewin

TESTIMONY EXPERIENCE
PHILIP R. WATTERS, P.E., M.B.A.

Testimony Date:	August 24, 1998
Cause Number:	96-1643 and 96-2187
Court:	United States District Court Eastern District of Louisiana
Style of Case:	Marathon Pipeline Company and Marathon Oil Company vs. LaRoche Industries, Inc. and Tassin International, Ltd.
Attorney:	Barry Bendetowies

ATTACHMENT H

Rate Schedule

MR. THOMAS J. KOCUREK	-	\$153.00 per hour
MR. ERNEST M. HONIG	-	\$153.00 per hour
MR. PHILIP R. WATTERS	-	\$180.00 per hour

46

1 IN THE UNITED STATES DISTRICT COURT
2 FOR THE SOUTHERN DISTRICT OF TEXAS
3 HOUSTON DIVISION

4 UNITED STATES OF AMERICA, :
5 Plaintiff, :

6 and :
7 :

8 THE STATE OF TEXAS, :
9 Plaintiff/Intervenor :

10 VS. : CIVIL ACTION NO. H-95-1118
11 :

12 KOCH INDUSTRIES, INC., :
13 et al :
14 Defendants :

15

16

17

18

19

20 ORAL DEPOSITION OF:

21 EDMOND RAPHAEL MURRAY, JR.

22 JUNE 25, 1999

23 VOLUME 1

24

25

26

27

28

29

30

1 THE REPORTER: The time is 9:41 and
2 we're on the record.

3

4 EDMOND RAPHAEL MURRAY, JR.,
5 having been first duly sworn, testified as follows:

6

7 DIRECT EXAMINATION

8 BY MR. VICKERS:

9 Q. Mr. Murray, my name is Harrison Vickers
10 and I represent the State of Texas in the
11 litigation in which you've been employed as an
12 expert. You understand that?

13 A. I do.

14 Q. And we've had a few opportunities to meet
15 each other at other proceedings; and to that
16 extent, you understand that my position is adverse
17 to your employer, do you not?

18 A. Yes, I do.

19 Q. For the purposes of the record, I want to
20 make sure that you're aware that this is testimony
21 under oath. You do understand that?

22 A. Yes, I do.

23 Q. And you understand if you were to give us
24 any untruthful responses, that you'd be subject to
25 all the penalties of perjury?

1 But once more, it would depend upon the depth and
2 size of the dent. A difficult dent in any state
3 would be a hazard. A slight dent in any state
4 would be a negligible hazard.

5 Q. Well, in your experience, do they change
6 out slight dents or negligible hazards?

7 A. Sometimes.

8 Q. So you can agree that when the people that
9 have their hands on this pipeline meet and say they
10 want to change out dents and bad road bends, that
11 they perceived it to be a problem?

12 MR. WEITZEL: Asked and answered.

13 A. If we limit our discussion to the dents
14 and bends in one particular road, there is evidence
15 here that they had an intention to change them
16 out. If you try to talk about problems with a
17 pipeline, the kinds of things that you would find
18 with an inspection tool across the entire length of
19 the line, I find nothing in this package to tell me
20 that they had any reason to anticipate a problem of
21 that sort.

22 Q. (By Mr. Vickers) Okay. Can you agree
23 from looking at this package, Exhibit No. 2, that
24 they wanted to smart pig the line in 1992?

25 A. There is evidence that as early as 1992,

1 smart pigging of this line segment was on their

2 wish list.

3 Q. In fact, in your Conclusion 16, don't you

4 say that Koch had used these tools exclusively as

5 their availability and capability is warranted?

6 A. I believe I said they had used them

7 extensively.

8 Q. All right. You feel like this is in

9 support of your conclusion -- was it 16?

10 A. I would have to look.

11 Q. I'll look for you. Yes, 16. Smart pig is

12 an internal inspection tool. Correct?

13 A. Yes, it is.

14 Q. And in 1992, did smart pigs exist that

15 were capable of inspecting 10-inch pipelines?

16 A. Yes, they did.

17 Q. And at least prior to September the 25th

18 of 1992, the personnel -- the field personnel at

19 this facility are saying we need to smart pig this

20 pipeline, are they not?

21 A. They had it on their priority list for

22 smart pigging, yes.

23 Q. In fact, it's priority one, isn't it?

24 A. Yes, it is.

25 Q. Do you have any independent information,

1 that pipeline is not receiving the cathodic
2 protection that's required by DOT regulations? And
3 this is a DOT regulated line, is it not?

4 A. Yes, it is. I would have to look at the
5 DOT regulations to see how they handle that. I
6 believe they say it must be adequately protected
7 and this, you know, could -- one that misses the
8 .85 so close as this could very easily fulfill one
9 of the other criteria which would make it
10 acceptable. I just can't tell from the data I have
11 here. It does not meet the negative .85 criteria.

12 Q. Which is a minimum standard that's
13 required by law. Is that not correct? Does not
14 DOT require you to install and maintain cathodic
15 protection on DOT regulated lines?

16 A. It requires you to protect your lines as
17 appropriate -- as required.

18 Q. Okay. And is the generally accepted
19 standard in the industry, and in particular in Koch
20 Industries, minus 850 millivolts?

21 A. That is one of four acceptable tests.

22 Q. Okay.

23 A. It is one most often used in the field
24 because it's the easiest to do.

25 Q. And this one Koch has failed, is that

1 correct, as depicted by this chart?

2 A. This one does not fully meet the minimum

3 .85 standard.

4 Q. Can you tell me if they passed any of the

5 three alternative tests?

6 A. I do not know.

7 Q. Do you have any information to indicate

8 that they did?

9 A. I have no information either way.

10 Q. That has not been supplied to you by the

11 Koch lawyers?

12 A. No.

13 Q. And you haven't asked for it?

14 A. No.

15 Q. Okay. Taking Exhibit 3 and 4 together,

16 Mr. Murray, are you starting to have any concern

17 about the safety of this pipeline?

18 A. Not necessarily, no.

19 Q. I mean, they've talked about -- the people

20 that are operating this segment of line, have

21 talked about the fact that it's got some dents and

22 some bad road bends and that was not a concern. Is

23 that correct?

24 A. It is a concern but they had been able to

25 see it apparently or they wouldn't have known they

1 were there. They had evaluated them and were
2 planning to fix them but obviously the visual
3 examination did not imply an emergency.

4 Q. Well, is it more likely since they've
5 mentioned it twice in their notes that they didn't
6 fix it because they couldn't get the slack time
7 that they needed to do repairs?

8 A. I don't know that but that kind of repair
9 would require some downtime.

10 Q. Okay.

11 A. Unlike the other things we've talked
12 about. You have to take the line down, do a little
13 drain up and cut out a piece of pipe, weld it in
14 and then start back up.

15 Q. Okay.

16 A. I don't know, but that it does take
17 downtime.

18 Q. But they talked about wanting to change
19 out that section. They talked about wanting to
20 smart pig it for over, oh, I think an 18, 19-month
21 period, did they not?

22 A. For a period of time, certainly.

23 Q. And the only stated reason that they
24 hadn't completed the smart pig was that they,
25 again, could not find slack time. Is that correct?

1 Q. But to the best of your knowledge, has

2 Koch adopted any system other than NACE for

3 cathodic protection?

4 A. Other than NACE?

5 Q. Yes.

6 A. These are all NACE standards I'm talking

7 about. To my knowledge, they have not adopted

8 anything different.

9 Q. All the Koch cathodic protection that I've

10 seen is based on some NACE standard. Is that true

11 for you as well?

12 A. Yes, it is.

13 Q. Okay. And under the NACE standards and

14 under the standards adopted by Koch and the

15 documents we've looked at for the -- at least two

16 years preceding this spill, they were below the

17 minimum line prescribed by their own rules, were

18 they not?

19 A. I believe that that is true in the time

20 the readings were taken.

21 Q. And being below that minimum standard,

22 they had placed themselves in a condition where

23 corrosion could occur. Is that correct?

24 A. As far as we could tell from that test, it

25 would be possible for corrosion to occur in that.

1 THE STATE OF TEXAS :

2

3

4 I, Lesia J.P. Wagner, Certified Shorthand

5 Reporter in and for the State of Texas, hereby

6 certify that at the time and place stated, the

7 witness, EDMOND RAPHAEL MURRAY, JR., personally

8 appeared before me, and after being by me first

9 duly sworn to tell the truth, was examined by

10 counsel for the respective parties hereto; that the

11 testimony of said witness was taken in shorthand by

12 me, later reduced to typewriting under my

13 direction, and the foregoing 198 pages is a true

14 and correct transcript of said testimony.

15

16

17

18 GIVEN UNDER MY HAND AND SEAL OF OFFICE on
19 this 12th day of July, 1999.

20

21

22

23

24

25

Lesia J.P. Wagner, Texas CSR 3561
Expiration Date: 12-31-2000
3000 Wesleyan, Suite 344
Houston, Texas 77027
(713) 572-2000

49

DEC 31 09:48 TO: 5128837221

In The Matter Of:

*Kevin Harms v.
Koch Gathering Systems, Inc.*

*John Lacy
December 12, 1997*

*Houston Reporting Services
1111 Fannin, Suite 1400
Houston, TX U.S.A. 77002
(713) 739-1400 FAX: (713) 739-1410*

Original File lacy.prt, 207 Pages
Min-U-Script® File ID: 1653534706

Word Index included with this Min-U-Script®

DEC 31 09:49 TO: 5129837221
 KEVIN MARINS V.
 Koch Gathering Systems, Inc.

FROM: JSTON COMPANIES T-325 P.83

JULIE LACY
 December 12, 1997

Page 1
 IN THE DISTRICT COURT OF NUECES COUNTY, TEXAS
 347TH JUDICIAL DISTRICT
 KEVIN MARINS, ET AL.)
 VS.) MC 044628-H
 KOCH GATHERING SYSTEMS, INC.)
 DAVID FOGG, JUAN AND RICHARD TUTTLE)
 DEPOSITION OF JOHN LACY
 DEPOSITION AND ANSWERS OF JOHN LACY,
 taken before T. B. Bode, a certified shorthand
 reporter and notary public in and for Montgomery
 County and the State of Texas, at the Law Offices
 of Sacramento & Clegg, L.L.P., One Houston Center,
 1221 McKinney, Suite 650, Houston, Texas
 77010-2003, beginning at 10:45 a.m. on the 12th
 day of December A.D. 1997, pursuant to the Texas
 Rules of Civil Procedure and the following
 stipulations:

STIPULATIONS

(1) IT IS STIPULATED AND AGREED by
 and (2) between counsel for the res-
 pective parties hereto (3) that the orig-
 inal deposition will be sent to the (4)
 witness for his review and signature; (5)
 IT IS STIPULATED AND AGREED by and
 (6) between counsel for the respective
 parties hereto (7) that an unsigned copy
 of the deposition can be (8) used in lieu
 of the original if not returned.

Page 3
 APPEARANCES
 MR. VERNON N. REASER, JR. 202 Pecan
 Drive, Victoria, Texas 77905-0009, representing
 the Plaintiff.
 MR. CHARLES D. KIPPLE of the Law Offices
 of Sacramento & Clegg, L.L.P., One Houston Center,
 1221 McKinney, Suite 650, Houston, Texas
 77010-2003, representing the Plaintiff.
 MR. RAFAEL BERNARDINO, JR. of the Law
 Offices of DENNIS HORNBLOWER, MANNING & WARD,
 P.O. Box 2728, Corpus Christi, Texas 78402,
 representing the Defendants.

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 (1) THE COURT REPORTER: Is this taken

(2) pursuant to the rules?
 (3) MR. REASER: The Texas rules, and (4)
 we reserve all objections until trial
 except as to (5) form.
 (6) MR. BERNARDINO: Right. Agreed.
 (7) THE COURT REPORTER: What
 would you (8) like to do about signature?
 (9) THE WITNESS: I'll sign it.
 (10) MR. KIPPLE: Vern, do you want him
 (11) to sign?
 (12) MR. REASER: Yes.
 (13) MR. KIPPLE: Okay. Send it to me, (14)
 and we can get it to him.
 (15) MR. REASER: Send the original. (16)
 He's got to sign it, so he's got to review
 the (17) original to sign. And I just want a
 condensed (18) copy and then one regu-
 lar copy.
 (19) THE COURT: If the original doesn't
 (20) get returned -
 (21) MR. REASER: A copy in lieu of the
 (22) original.

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 (1) JOHN LACY,
 (2) called as a witness, having been first
 duly sworn, (3) was examined by counsel
 and testified as follows:
 (4) EXAMINATION
 (5) QUESTIONS BY MR. BERNARDINO:
 (6) Q: Good morning, Mr. Lacy.
 (7) A: Good morning.
 (8) Q: My name is Rafael Bernardino, and
 I'm (9) with the firm of Demars, Hor-
 nblower, Manning & (10) Ward. We re-
 present the defendants in this matter. (11)
 I'm going to be taking your deposition
 this (12) morning.
 (13) The first thing I'm going to ask (14) you
 to do is state your name for the record
 and (15) spell your last name.
 (16) A: Okay. John Franklin Lacy, and my
 last (17) name is spelled La-cy.
 (18) Q: Mr. Lacy, I don't mean to bore you,
 but (19) I'll go through a few preliminaries
 for the record (20) here.
 (21) A: Sure.
 (22) Q: We're in an informal setting in a (23)
 lawyer's office this morning, but you
 have taken

Page 7
 (1) an oath to tell the truth, and your
 testimony here (2) today is as binding as if
 it would have been given (3) in court.
 (4) For that reason, we want to make (5)
 very certain that you give your best
 testimony. (6) If I ask any questions that
 you don't understand (7) or is confusing
 to you, unlike court, you can tell (8) me
 that there's something about my ques-
 tion you (9) don't understand or ask me to
 restate it; and I'll (10) do my best to put it in
 a clearer framework for (11) you.

(12) Secondly, we don't want you to (13)
 guess or speculate. Obviously, you're an
 expert (14) in this field, and if you choose
 to make an (15) approximation or other
 assumptions based on your (16) know-
 ledge, that's okay. But other than that, we
 (17) don't want you to guess or speculate
 as to any (18) issues involved.
 (19) When I say we wanted your best (20)
 testimony, you can see our reporter is
 putting it (21) down, and she will put it in
 booklet form, which (22) you're going to
 have an opportunity to review, and (23) at
 that time you can make any changes you
 wish to (24) make to it. However, if you do
 make such changes, (25) we could com-
 ment on them at trial, and it could

Page 8
 (1) effect on how your testimony is
 viewed. So that's (2) why we really want
 to get your best testimony here (3) today.
 (4) Also, unlike court, if you want to (5)
 take a break at any time for any reason,
 you can (6) do that here, so just let us
 know.
 (7) That being said, is there any (8) reason
 why we can't conduct your deposition
 today?
 (9) A: No.
 (10) Q: Okay. Sir, I'm going to provide you
 (11) with a document, and it will be the
 first exhibit (12) today.
 (13) It's a Notice of Deposition to Take (14)
 Oral Deposition of John Lacy. By agree-
 ment of (15) counsel, the date and time has
 been changed, but (16) I'm going to draw
 your attention to item No. 5. (17) And if we
 can get the court reporter to mark this
 (18) as an exhibit.
 (19) (Exhibit was marked for (20) iden-
 tification by the court reporter as Lacy
 (21) Deposition Exhibit No. 1.)
 (22) Q: (By Mr. Bernardino) Mr. Lacy, have
 you (23) had an opportunity to review this
 document before?

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 (1) A: Yes.
 (2) Q: The first item you were asked to
 bring (3) to the deposition was a copy of
 your curriculum (4) vitae. Do you have a
 copy?
 (5) A: Yes, I do. And I would like to hold
 on (6) to it. Or if you want to ask questions
 from it, (7) maybe get me copy to work
 from, too.
 (8) MR. BERNARDINO: Let's go off the (9)
 record a second.
 (10) (Discussion off the record.)
 (11) Q: (By Mr. Bernardino) Mr. Lacy, we're
 (12) going to mark as the exhibit next in
 order a copy (13) of your curriculum
 vitae. All right?
 (14) (Exhibit was marked for (15) iden-
 tification by the court reporter as Lacy
 (16) Deposition Exhibit No. 2.)

DEC 31 '97 10:01 TO: 5128837221
KEVIN MARTIN V.
Koch Gathering Systems, Inc.

FROM: HOUSTON COMPANIES T-325 P. 15

JOHN LACY
December 12, 1997

(13) A: Well, there are other things that can (14) affect the suitability, too. And one of the (15) things you may do is either run some special (16) chemicals or flushes, and you may also run a (17) preliminary pig that doesn't have the expensive (18) hardware on it. So there's a process you go (19) through to be able to run a smart pig.

(20) Q: And is your assumption that all that was (21) done prior to the recommendation in the AFE?

(22) A: Not - not all of it. The part of it (23) that's going to cost money you wouldn't do till (24) you got the AFE approved, and it would all be done (25) as part of more or less a continuous operation.

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(1) Q: So it's fair to say then that it is an (2) assumption you make when evaluating the AFE that (3) whoever had to make the determination or review (4) had done so and the line was suitable for a smart (5) pig. Is that an assumption you made?

(6) A: Yes, yes.

(7) Q: All right. Now, have you done anything (8) to test that assumption?

(9) A: Not at this point.

(10) Q: Do you know if the line internally is (11) suitable to run a smart pig?

(12) A: I'm assuming this one is because it's my (13) understanding that after the rupture that they did (14) run a smart pig.

(15) Q: And the -

(16) A: But that would also, I suppose, be part (17) of my assumption that this was a suitable (18) situation.

(19) Q: Okay. In regards to - Do you know the (20) portions of the line that they ran the smart pig (21) through?

(22) A: I know I have reviewed that, but it's - (23) but it's been a while, so I couldn't tell you the (24) exact portions.

(25) Q: Okay. Now, why do you believe that Koch

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(1) refused to correct or repair its condition?

(2) A: Based on what's come out so far, there's (3) been an indication in the depositions that they (4) knew that they were not going to be using this (5) line in a few more years, and they wanted to (6) minimize what they spent on it.

(7) Q: Okay. Which leads to my next question. (8) This second part of this first opinion that Koch (9) refused to correct or repair its condition, is (10) there any document or testimony that you relied on (11) in forming this part of the opinion?

(12) A: Yeah. That was - that was in the (13) depositions that were done in Corpus by the two (14) gentlemen, Williams and Stout.

(15) Q: The deposition of Mr. Williams and the (16) deposition of Mr. Stout?

(17) A: Uh-huh. That's correct.

(18) Q: And what in their testimony causes you (19) to believe this?

(20) A: That's what they said.

(21) Q: What, that Koch -

(22) A: That they knew they were not going to be (23) using that line much longer and didn't want to (24) spend the money.

(25) Q: Is that what they said?

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(1) A: Yes.

(2) Q: Okay. Has there come a time when Koch (3) stopped refusing to correct or repair this (4) condition?

(5) A: It's my understanding that - that after (6) the rupture and the repair was made, that they did (7) smart pig the line.

(8) Q: So at some point then they - this (9) refusal stopped?

(10) A: Yes, I would say so. I think there were (11) a number of other repairs made as a result of that (12) smart pig.

(13) Q: So when can we say the refusal - when (14) can we say the refusal stopped?

(15) A: I don't remember the exact date of that. (16) I didn't spend a lot of time on it because it was (17) quite a bit after this, but it seems like it was (18) in 1995. But that's - that's been documented. (19) I'm sure we can give you the exact times. I just (20) don't know as we sit here today.

(21) Q: Okay. So approximately 1995. Can you (22) tell me approximately when this refusal began, (23) when they initially refused to do this?

(24) A: Well, it's - These documents are dated (25) when the proposals were made, so I guess - I

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(1) guess that would be the easiest way to do it.

(2) I think one of them says what date (3) that it's dated, and the actual AFE is not in (4) these documents, but it would have the date on it (5) too.

(6) Q: So you would view the refusal date as (7) the date of the RFE?

(8) MR. REASER: AFE.

(9) A: (Continuing) This document, (10) K-CCP-016247, item No. 1, Ingleside to - (11) Ingleside to Mayo 10-Inch Smart Pig. Ricky will (12) turn in AFE September 25th, 1992.

(13) Q: So -

(14) A: So that would be an approximate date.

(15) Q: Are there any other documents or (16) testimony that you relied on in forming this (17) portion of your opinion?

(18) A: Substantially, that would be it. I may (19) have seen similar statements on other documents, (20) but I think these that we've already discussed (21) would - would be the main ones.

(22) Q: Do you have in mind others that we're (23) not discussing right now?

(24) A: Well, this is another one that I - that (25) I've look at. Again, I think the same things that

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(1) are being talked about here are the same numbers (2) that we've looked at.

(3) Q: Which document -

(4) A: But I guess I would include these with (5) that. You may just want to look at them. It (6) would be easier for you to read than for me to (7) tell you.

(8) Q: I'm sorry. Which documents are you (9) referring to?

(10) A: If you look at the Bates numbers on (11) these, they're the same documents that we've (12) already stuck in here.

(13) Q: Okay. We're referring to this document. (14) I guess this is the second time we've referred to (15) it, so I'm going to ask her to make this next in (16) order, and then we can just refer to it.

(17) A: Okay.

(18) (Exhibit was marked for (19) identification by the court reporter as Lacy (20) Deposition Exhibit No. 11.)

(21) Q: (By Mr. Bernardino) And in regard to my (22) question, are you referring to the first four of (23) these entries, February '92, September '92 - or

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(1) which ones are you referring to?

(2) A: The first five there.

(3) Q: The first five entries, and those are (4) the entry for February '92, September '92, (5) November '92, June '93 and September '93?

(6) A: Right.

(7) Q: Okay. Anything else?

(8) A: To the best of my knowledge - Please (9) understand, I've looked at thousands of pages of (10) documents. Some of the same event I've seen (11) multiple versions of. So when I've gone back to (12) get this support out, once I find the first one or (13) two of those, that's what I'm showing you. But (14) there very well may be others in that stack that (15) shows some of the same things.

(16) Q: Well, that's what we try to do, we try (17) to find -

(18) A: I guess if during our further work we (19) run across some of those others that we either (20) want to make into an exhibit or use, we either (21) need to reserve the right to do that or notify you

DEC 31 '97 10:22 TO: 5128837221
 JOHN LACY
 December 12, 1997

FROM: HOUSTON COMPANIES T-325 P. 34

Koch Gathering Systems, Inc.

(5) Q: Are there documents or testimony that (6) you've used to support this figure?

(7) A: Okay. Yes.

(8) Q: Okay. And what are they?

(9) A: I'm sorry. Here in my report there's a (10) section that I deal with the Koch spill (11) calculation.

(12) Q: Separate from your report. I'm looking (13) for something that you used to create your report, (14) some document, testimony, anything?

(15) A: Well, there's a number of documents that (16) indicate that most of the people working with the (17) situation during that nine-day period knew that it (18) was more than 400 barrels, but nobody knew - (19) None - none of the people outside of Koch had the (20) information they needed to know exactly what.

(21) Q: Okay. You're way ahead of me.

(22) A: Okay.

(23) Q: My question is more basic.

(24) A: Okay.

(25) Q: You begin, "Our conservative estimate of

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(1) the total spill (5481 barrels)." Now, our (2) plaintiffs.

(3) A: Really, that's mine.

(4) Q: Okay. My question is, where did you get (5) this figure 5481?

(6) A: Okay. Part of it I got based on the (7) numbers that we discussed earlier where I added (8) 116 barrels.

(9) Q: Right.

(10) A: That's part of it. If you're - if (11) you're understanding that part, I'll go to the (12) other part.

(13) Q: Go to the other part.

(14) A: The other part is we know that the pumps (15) were turned back on and run more than an (16) additional hour after the rupture occurred, and (17) for whatever reason, Koch never showed any number (18) on that.

(19) In other words, they turned - they (20) turned the big pump back on and ran it for more (21) than an hour and pumped out this ruptured line (22) through a hole of something over 50 square inches, (23) and they didn't show any number for that amount (24) pumped.

(25) Q: Let me try to draw a mental picture

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(1) then.

(2) A: That's what I was trying to do, too.

(3) Q: All right. The pipeline is - Is this (4) what you're saying, that the pipeline was pumping (5) oil when the ruptured

occurred; and when this (6) system - the pump stopped, all that oil that was (7) between the pump and the rupture spilled out of (8) the pipeline? Is that what you're saying?

(9) A: What I'm saying is in addition to (10) this whatever - whatever the linefill ends up (11) being, 26, 2800 barrels, in addition to that (12) amount, they turned the pumps back on and pumped (13) an additional amount -

(14) Q: Our.

(15) A: - out.

(16) Q: Okay.

(17) A: So that's that.

(18) Q: It was - Your total is what was in the (19) system when the ruptured occurred and drained out (20) and then when the pump was restarted?

(21) A: Yeah.

(22) Q: A full hour's worth of crude pumped (23) through and drained out?

(24) A: Yeah.

(25) Q: And that's how you arrive at this 5481

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(1) barrel figure?

(2) A: Yeah, the two of those together.

(3) Q: And the documents to support that are (4) where?

(5) A: Well -

(6) Q: Or testimony, whatever you've got.

(7) A: Koch - Koch's made their calculation (8) and give us this initial linefill figure of 2678. (9) And I - I've got - I've got that here.

(10) All right. In addition to that, we (11) see here on these two pressure charts -

(12) Q: Exhibits 15 and 16?

(13) A: And on those Alarm Queries that they (14) pumped for - both pumps for more than an hour, (15) and the other pump for some several minutes more (16) than that. So that's the documents.

(17) Q: Exhibits -

(18) A: The Alarm Query, these two pressure (19) charts, and the calculation that Koch did that has (20) this 2600 and whatever it is.

(21) Q: Exhibits 12, 15 and 16, and what else (22) are you referring to? You're pointing to (23) something. I can't see what you're looking at.

(24) A: Oh, they talk about that in the (25) deposition.

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(1) Q: Which deposition is that?

(2) A: That's Stout's - Calvin Stout's.

(3) Q: Okay. I've reached sort of a natural (4) breaking point at this one now, so why don't I (5) stop right now, and we would

need to reconvene.

(6) A: Here's the linefill.

(7) Q: Let's finish it up. Let's mark this (8) next in order. This is the linefill that you're (9) making reference to?

(10) A: Uh-huh.

(11) Q: This is a document you received from (12) Koch?

(13) A: Yes.

(14) Q: Okay. Let's mark that next in order, (15) and I guess that's the last question for now.

(16) Exhibit was marked for (17) identification by the court reporter as Lacy (18) Deposition Exhibit No. 19.

(19) Exhibit No. 17 will be faxed by the (20) witness and marked.

(21) Exhibits marked for identification (22) by the court reporter during the deposition are (23) attached hereto.)

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John Lacy
 THE STATE OF TEXAS)
 COUNTY OF HARRIS)
 SUBSCRIBED AND SWORN to before me, the
 undersigned authority, on this _____ day
 of _____, 1998.
 My Commission _____ Notary Public
 Expires _____ and for Harris County and
 the State of Texas

Page 203

STATE OF TEXAS)
 COUNTY OF MONTGOMERY)
 I, the undersigned certified shorthand
 reporter and notary public in and for Montgomery
 County and the State of Texas, hereby certify that
 the facts as stated by me in the caption hereto
 are true; that the above and foregoing answers of
 the witness named in said caption to
 interrogatories as indicated were made before me
 by said witness after being first duly sworn to
 testify the truth, and the same were thereafter
 reduced to typewriting under my direction.
 I certify that the above and foregoing
 deposition as set forth in typewriting is a full,
 true and correct transcript of the proceedings had
 at the time of the taking of said deposition.
 I further certify that charges for the
 preparation of the foregoing completed deposition
 were \$ _____ for the original thereof charged to
 Mr. Robert Somerville, Jr., Attorney for the
 Defendants, Bar No. 20841500.
 IN TESTIMONY WHEREOF, witness my hand or
 this _____ day of _____ A.D., 1997
 My Commission _____
 Exp. 1-20-1998 Trade F. Bode, Certified Shorthand
 CSR No. 8480 Reporter and Notary Public in and
 Exp. 12-31-96 for Montgomery County and the State
 of Texas

Page 204

IN THE DISTRICT COURT OF NUECES COUNTY, TEXAS
 24TH JUDICIAL DISTRICT
 KEVIN MARAS, ET AL.)
 VS.) NO. 94-0029-H
 KOCH GATHERING SYSTEMS, INC.,)
 DAVID FOGELMAN AND RICHARD TUTTLE)
 CERTIFICATE OF CERTIFIED SHORTHAND REPORTER
 TAKING DEPOSITION OF WITNESS
 JOHN LACY

ON THE 12TH DAY OF DECEMBER, 1997
 THE STATE OF TEXAS)
 COUNTY OF MONTGOMERY)

I, Trade F. Bode, a certified shorthand
 reporter and notary public in and for the State of
 Texas, hereby certify the following is true and
 correct:

(1) that the witness was duly sworn by me as
 the officer

(2) that the foregoing transcript to which
 this certification is attached is a full, correct
 and true record of the testimony given by the

DEC 31 '97 10:23 TO: 5129837221

FROM: HOUSTON COMPANIES

T-325 P. 35

Koch Gathering Systems, Inc.

December 12, 1997

Witness: _____ is the amount of
(3) \$ _____ charges paid by Mr. Rafael Bernardino, Jr., the
Attorney for the Defendants, Bar No. 20341600, for
the officer's preparation of the completed

Page 205

(1) deposition transcript and any copies of exhibits; (2) (4) that the deposition transcript was not (3) submitted / was submitted on the _____ day (4) of _____, 1997, to the witness, John Lacy, (5) for his examination, signature and return to the (6) officer by the day of _____, 1998; (7) (5) that changes, if any, made by the (8) witness in the transcript and otherwise are (9) attached thereto or incorporated therein; (10) (6) that the attorney did return / did (11) not return the transcript; (12) (7) that the original deposition transcript (13) or a copy thereof in the event the original was (14) not returned to the officer, together with copies (15) of all exhibits, was delivered, or mailed in a (16) postpaid properly addressed wrapper, certified (17) with return receipt requested to Mr. Rafael (18) Bernardino, Jr., the attorney or party who asked (19) the first question appearing in the transcript; (20) for safekeeping and use at trial; (21) (8) that a copy of the certificate was / (22) was not served on all parties or their (23) attorney of record pursuant to the Texas Rules of (24) Civil Procedure 21a. Said parties or their (25) attorney of record as listed as follows:

Page 206

(1) MR. VERNON N. REASER, JR. 202 Pecan Drive, (2) Victoria, Texas 77905-0666; (3) MR. CHARLES D. KIPPLE of the Law Offices of (4) Saccomanno & Clegg, L.L.P., One Houston Center, (5) 1221 McKimney, Suite 650, Houston, Texas (6) 77010-2003; (7) MR. RAFAEL BERNARDINO, JR. of the Law Offices (8) of DEMARS, HORNBLOWER, MANNING & WARD, P.O. Box (9) 2728, Corpus Christi, Texas 78403; (10) (9) that a copy of the certificate was filed (11) by me on the day of _____, 1998, with (12) the court in which cause is pending; and, (13) (10) that I, the undersigned notary public (14) and certified shorthand reporter, whose signature (15) appears below, certify that I am not counsel, (16) attorney, or relative of any party in the case of (17) otherwise interested in the case; and, (18) (11) that the attorneys for the respective (19) parties agree / did not agree that a copy (20) can be used in lieu of the original; therefore, (21) the certificate is being filed prior to the time (22) the original is returned so that taxable cost may (23) be entered.

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GIVEN UNDER MY HAND AND SEAL OF OFFICE
on this _____ day of _____, 1998.
My Commission _____
Exp. 1-20-1999 Mike F. Bode, Certified Shorthand
CSR No. 6430 Reporter and Notary Public in and
Exp. 12-31-98 for Montgomery County and the State
of Texas

48

In The Matter Of:

*Kevin Harms, et al v.
Koch Gathering Systems, Inc., et al*

*Garry Mauro
December 15, 1997*

*FREDERICKS-CARROLL REPORTING & VIDEO, INC.
Court Reporting-Video Services-Litigation Support
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(1) NO. 94-6629-H
 (2)
 (3) KEVIN HARMS; DAVID) IN THE DISTRICT COURT
 FANCHIER; WILLIAM)
 (4) COMPTON; ROMEO GARZA)
 GARCIA; WILLIAM CORANATO;)
 (5) PETER R. GONZALEZ; JANE)
 STUBBS; and on behalf of)
 (6) all others similarly)
 situated)
 (7)
 (8) VS.) NUECES COUNTY, TEXAS
 (9)
 (10) KOCH GATHERING SYSTEMS,)
 (11) INC.; DAVID FOGELMAN; AND)
 (12) RICHARD TUTTLE) 347th JUDICIAL DISTRICT
 (13)
 (14) ORAL DEPOSITION OF GARRY MAURO
 (15) On the 15th of December, 1997, between
 (16) the hours of 10:13 a.m. and 11:56 a.m., in the
 (17) offices of The Office of the Commissioner, Texas
 (18) General Land Office, Stephen F. Austin Building,
 (19) 1700 North Congress Avenue, 8th Floor, Austin,
 (20) Texas 78701, before me, Deborah L. Fitzpatrick, a
 (21) Certified Shorthand Reporter for the State of
 (22) Texas, appeared GARRY MAURO, who, being by me first
 (23) duly sworn, gave an oral deposition at the instance
 (24) of the Plaintiff in said cause, in accordance with
 (25) the provisions as attached hereto.

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(1) APPEARANCES:
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 (5) -and-
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 (8)
 (9) For Koch Gathering Systems, Inc.
 Mr. Robert J. McCully
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 (11)
 (12) For David Fogelman and Richard Tuttle
 Mr. Kent E. Westmoreland
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 (15) For Texas General Land Office
 Ms. Ingrid Hansen
 (16) Texas General Land Office
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 (17) and Response
 Stephen F. Austin Building
 (18) 1700 North Congress Avenue, 8th Floor
 Austin, Texas 78701
 (19) -and-
 (20) Mr. Harrison Vickers
 The Vickers Law Firm
 40th Floor
 (21) 700 Louisiana Street
 Houston, Texas 77002
 (22)
 (23) Also Present:
 (24) Mark Wolfington, Videographer
 (25)

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(1) GARRY MAURO,
 (2) the witness hereinbefore named, being first duly
 (3) cautioned and sworn to testify the truth, the whole -
 (4) truth and nothing but the truth, testified as
 (5) follows:
 (6) THE VIDEOGRAPHER: I'm on the record.
 (7) 10:18 a.m.
 (8)
 (9) EXAMINATION
 BY MR. EDWARDS:
 (10) Q: Would you tell the jury your name,
 (11) please, sir?
 (12) A: I'm Garry Mauro, Texas Land
 (13) Commissioner.
 (14) Q: How are you presently employed?
 (15) A: By the State of Texas and the people of
 (16) Texas as the Texas Land Commissioner.
 (17) Q: You live here in Austin?
 (18) A: As required by the State Constitution.
 (19) as a constitutional office holder, I reside in the
 (20) State of - I reside in Austin, Texas.
 (21) Q: Are you represented by counselor today
 (22) here?
 (23) A: Yes. I have Ingrid Hansen, who is a
 (24) staff lawyer.
 (25) Q: That's a staff lawyer with the General

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(1) TAC Section 1932. Can you tell me what that is
(2) (handing)?
(3) A: (Witness peruses document).
(4) It appears to be the rule that we
(5) promulgated at the General Land Office to deal with
(6) oil spill prevention and response.
(7) Q: All right.
(8) Did Koch Refining or Koch - I don't
(9) know whether it's Refining or not. Did Koch - let
(10) me put it this way. Let me strike that other
(11) question and put it this way.
(12) Was the General Land Office informed
(13) about a spill in Nueces and Corpus Christi Bays
(14) involving Koch Gathering Systems that occurred
(15) sometime in October, 1994?
(16) A: Yes.
(17) Q: Can you recall when you, personally,
(18) first became aware of that spill, not in terms of a
(19) date, but in terms of how close to the time that
(20) the spill occurred?
(21) A: I cannot remember the exact time.
(22) Q: All right.
(23) A: I mean, it was within - understand
(24) historically, I would not know about small spills.
(25) I would only be informed of big spills, medium

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(1) sized spills, or problem spills.
(2) Q: All right.
(3) So what you're telling the jury is
(4) that you would not hear about the spill until it
(5) became - until somebody with the Commission became
(6) aware that it was either a big spill or a -
(7) A: Problem spill.
(8) Q: - problem spill?
(9) A: Yes.
(10) Q: Did you have occasion to have any
(11) communication with Koch with regard to that spill?
(12) A: I think I sent them a letter.
(13) (DEPOSITION EXHIBIT NO. 1, MARKED).
(14) BY MR. EDWARDS:
(15) Q: Let me ask you to look at the exhibit
(16) that I've marked as Mauro Discovery Exhibit No. 1
(17) and ask you if you can identify that (handing)?
(18) A: (Witness peruses document).
(19) This is a letter I sent to the - to
(20) Koch Industries in regard to this particular spill.
(21) Q: On that particular copy there are some
(22) notations in somebody's hand at the top. Do you
(23) have any idea who put those notations there?
(24) A: No, I don't.
(25) Q: Would they have been there when you sent

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(1) the letter?
(2) A: Probably not. They were added
(3) afterwards.
(4) Q: What was the occasion that caused you
(5) to - or what occasioned your writing that letter?
(6) A: I think I had at least one meeting and
(7) possibly as many as three with my staff about this
(8) particular spill, and it was at their
(9) recommendation that we sent the letter.
(10) Q: All right.
(11) And what was the main concern or the
(12) main reason you had for writing that letter?
(13) A: The notification component of the spill
(14) by Koch was being questioned in this letter.
(15) Q: Had the size of the spill changed over
(16) time from the initial report to when you wrote the
(17) letter?
(18) A: Yes.
(19) Q: Was that change in the size of the spill
(20) material to the Land Office?
(21) A: Yes, it was.
(22) Q: Would you explain why that was?
(23) A: Well, as the letter states, the original
(24) notification to the Land Office talked about it -
(25) the discharge being approximately ten barrels. A

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(1) ten-barrel spill would not be something that would
(2) raise any flags in our office. We would send
(3) minimal amount of equipment and personnel to a
(4) location. Within four hours, we were told it was a
(5) four hundred barrel spill. We were later contacted
(6) and said it was a five hundred barrel spill. My
(7) staff came to believe that it was over two thousand
(8) barrels. That's a significant difference. Had we
(9) known two thousand barrels in the first place, we
(10) would have responded totally different than we
(11) would with a ten-barrel or even a four or five
(12) hundred barrel spill.
(13) Q: In what way would you have responded
(14) differently?
(15) A: We would have done three things. We
(16) would have had more of our own personnel and
(17) equipment on location. We would have discussed
(18) with the Koch what - how their contingency plan
(19) was functioning. And we would have probably,
(20) depending on how much equipment we were able to
(21) bear and how comfortable we felt with their
(22) contingency plan, had contracted with
(23) subcontractors of our own to get additional
(24) equipment and personnel there as soon as possible.
(25) Q: Did the information in the way it was

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(1) provided to the General Land Office result in a
(2) delay in response?
(3) A: Absolutely.
(4) Q: What has been your experience is the
(5) effect of a delay in response of this kind?
(6) A: It creates a situation where you have
(7) the extreme risk of destroying the ecosystem and
(8) creating damage to the surrounding ecosystems.
(9) Q: Let me go back just a minute to the
(10) function, in general, of the General Land Office in
(11) responding to these oil spills and the role that
(12) the Land Office plays in that regard.
(13) Have you been personally involved in
(14) the development of those plans and that function of
(15) this department?
(16) A: Yes.
(17) Q: Would you explain to the jury what that
(18) involvement has been?
(19) A: Well, I'm not quite sure what -
(20) Q: Well, in general.
(21) A: Conceptually, the whole idea that we
(22) deal with marine spills in Texas is different from
(23) everybody else's in the country, if not the world,
(24) and that came as a result of the Alaskan Valdez
(25) spill. When I woke up one morning and saw on TV

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(1) that we had a major spill in Valdez, Alaska, and it
(2) was causing an extreme amount of damage to the
(3) environment and to the local economy, I recognized
(4) at that point that I was sitting on oil spill
(5) prevention response committees, and that's all they
(6) were, were committees of different state and
(7) federal agencies that were supposed to respond to
(8) marine spills in Texas. And I recognized that if
(9) something like the Valdez incident happened in
(10) Texas, we would have no way to respond quickly. We
(11) would have to be - we would be solely dependent
(12) upon how the company responded.
(13) So I spent a significant amount of
(14) time and effort making myself acquainted with oil
(15) spills in a marine environment. And I came to the
(16) conclusion after talking to the experts all over
(17) the world, that you had to respond to a marine oil
(18) spill like you do a fire. You have to drill, you
(19) have to have equipment, you have to have trained
(20) personnel to know exactly what to do. And when a
(21) spill occurs, you have to go big quickly. You have
(22) to have redundancy in the system, so that you can
(23) go big quickly.
(24) And so we prepositioned personnel and
(25) equipment that are on the state's payroll. We

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(1) prepositioned contracts with subcontractors and
(2) audited them to make sure they had equipment
(3) available so that they could respond to help us
(4) when we had insufficient equipment and personnel.
(5) And then working with the people who move and
(6) receive oil, we set about making certain they had
(7) enough equipment and trained personnel to deal with
(8) what their contingency plans that were filed with
(9) this office.

(10) So there are three ways you can deal
(11) with an oil spill in Texas now. You can - you,
(12) first of all, are going to look to the mover of the
(13) oil - the mover of the oil, receiver of the oil,
(14) their own equipment, their own personnel, and their
(15) own contingency plans. You have the state's
(16) prepositioned equipment and personnel in place, and
(17) then we have contracts with subcontractors to deal
(18) with spills that are of a quantity that can't be
(19) dealt with sufficiently by the first two.

(20) Now, all of that, you're asking
(21) how - all of that took, literally, months, and
(22) thousands of hours to put in place. I mean, first
(23) we had to find out if that was the correct and best
(24) way to deal with spills. Then we had to work with
(25) the industry to convince them that that was the

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(1) best way to approach it. Then we had to pass a law
(2) in the legislature to give us the authority to
(3) approach oil spills in that manner. And then we
(4) had working groups of industry and interested
(5) citizens and law makers to implement the law with
(6) our rules. So this has been a pyramid process
(7) where we laid the foundation, passed the law, and
(8) implemented the law with broad-based support.

(9) Q: All right.
(10) And do you consider this an important
(11) function?

(12) A: Well, it's extremely important.

(13) Q: Why is that?

(14) A: Because, as I pointed out, this - when
(15) an oil spill occurs in a marine environment, it's
(16) not something that you can say, okay, it's Easter
(17) weekend, let's wait till we all get back from our
(18) holiday on Monday morning. If you wait until
(19) Monday morning, you put the entire ecosystem at
(20) extreme risk. And our economy in Texas, those
(21) ecosystems not only good quality of life, places to
(22) spend time, they directly affect the economy in our
(23) state. So while you wait - while you spend the
(24) weekend waiting for everybody to get back from
(25) work, you could have actually destroyed the

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(1) economic basis of whole sections of our coastline.
(2) Very similar to what happened in Alaska. I mean,
(3) they still haven't recovered.

(4) Q: All right.

(5) Is there any difference in your mind
(6) between waiting until Monday, as you've explained,
(7) or under-reporting the amount of the spill by -
(8) A: Very little.

(9) Q: - by 200 percent, 2,000 percent, or
(10) whatever it might be?

(11) A: I mean, the only difference is that
(12) hopefully one of the General Land Office personnel
(13) will be on site and be able to determine there is
(14) an under-reporting. I mean, the problem, of
(15) course, is that some of these sites are very remote
(16) and difficult to get to.

(17) Q: Of all these responses that are in place
(18) that the state has provided for under statute and
(19) your auspices as General Land Commissioner, do any
(20) of them work if the spill isn't reported?

(21) A: No.

(22) Q: What happens when the spill is
(23) under-reported insofar as these responses working
(24) as they ought to?

(25) A: If a spill is under-reported, you don't

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(1) bring enough personnel on site and you don't bring
(2) enough equipment to deal with the spill. In
(3) particular in remote sites, that will put your
(4) whole ecosystem at extreme risk.

(5) Q: In your letter, Exhibit 1, you opine
(6) that the estimate of the actual spill could have
(7) been calculated within hours of the discharge, not
(8) days. Can you recall at this time what the basis
(9) of that opinion was?

(10) A: Oh, sure. I mean, pipelines know how
(11) much oil is in their pipeline. Very similar to how
(12) a guy who owns a shoe store knows how many shoes
(13) he's got in the store. I mean, you keep track of
(14) your inventory. And it is inconceivable to me,
(15) knowing the federal regulations pipelines are
(16) under, federal requirements of the law for
(17) pipelines, the state requirements and regulations
(18) they're under, that you could have a discharge and
(19) a pipeline company not know within 5, 10, 15
(20) percent exactly what was spilled.

(21) Q: Can you recall offhand with whom you -
(22) first of all, did you have any personal
(23) conversations with anybody that was at the site of
(24) the spill?

(25) A: Yes.

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(1) Q: Did you happen to personally go to the
(2) site of the spill?

(3) A: No.

(4) Q: Can you recall any of those with whom
(5) you discussed this who were at the site?

(6) A: When we have an emergency like this, the
(7) head of the division calls me up and says we need
(8) to have a meeting and he brings several experts
(9) into the room.

(10) Q: When you say that division, which
(11) division?

(12) A: The Oil Spill Prevention and Response
(13) Division.

(14) Q: All right.

(15) A: And I assume former Coast Guard Officer
(16) Lukes who handles that asks for a meeting and
(17) brought several people into the meeting. I do not
(18) recall exactly who was in the meeting.

(19) Q: Okay. Did you ever happen to talk to a
(20) person by the name of Gabriel Lugo?

(21) A: Oh, sure.

(22) Q: Who was Gabriel Lugo?

(23) A: He ran the local office in Corpus
(24) Christi.

(25) Q: All right. Did he give you - did

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(1) Mr. Lugo give you any information that was contrary
(2) to the information that you have outlined in your
(3) letter to the Koch folks?

(4) A: Oh, no, not at all. I mean, the letter
(5) was toned down to what he recommended.

(6) Q: What did Mr. Lugo recommend?

(7) A: Mr. Lugo felt that the Land Office was
(8) purposely being not told the truth. I imply that
(9) in this letter, but I never said it.

(10) Q: All right.

(11) And in what regard did Mr. Lugo tell
(12) you that he thought that the Land Office was not
(13) getting the truth?

(14) A: I can't be certain if it was just
(15) Mr. Lugo. I think we were all in a room together,
(16) and I think what was - the information reported to
(17) me was, this is a very remote location. This was a
(18) weekend. For a ten-barrel spill, we would have
(19) been tempted just to kind of glance at it and walk
(20) away. And he believed that Koch felt that's what
(21) we would do rather than really investigate it and
(22) get serious about cleaning it up. And that is when
(23) we discovered there was more than ten barrels. He
(24) thought that Koch was stonewalling, thinking they
(25) could clean it up in the next week and we would

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(1) never know the difference.
(2) Q: Did you ever receive any response to
(3) this letter, Exhibit 1?
(4) A: Oh, yes.
(5) Q: From whom did you get the response?
(6) A: Whoever the - I received a phone call,
(7) as I mentioned in this letter and I do not remember
(8) who called me.
(9) Q: Okay.
(10) A: And then I - after I sent the letter, I
(11) was contacted and asked to schedule a meeting with
(12) Koch representatives. They have a local lobbyist
(13) here who I don't deal with much who came in and
(14) brought two or three people with him to talk about
(15) the letter.
(16) Q: All right.
(17) And -
(18) A: I think - I recall there was somebody
(19) from the legal staff out of headquarters, but I
(20) don't - I mean, we could go through my schedule
(21) and I could make that available to you.
(22) Q: Was - do you know whether there was an
(23) Allen Hollock or Hellock?
(24) A: I mean, that sounds familiar, but it
(25) would be much easier - my staff can provide you

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(1) with my schedule and all of that is public
(2) information, who I meet with. And I don't recall
(3) exactly who was in the meeting.
(4) Q: Do you recall anything about that
(5) meeting that bears on the issues we've been talking
(6) about here?
(7) A: Well, I mean - I recall two or three
(8) things about the meeting. First, they were a
(9) little upset with me because my letter was fairly
(10) strong. And second, they were also a little
(11) apologetic because the facts were that they had
(12) under-reported fairly significantly. Okay. More
(13) than fairly significantly. And third, we agreed
(14) that in the future we would have open lines of
(15) communications and we would do better - they would
(16) do better.
(17) Q: Did they acknowledge that it had been
(18) under-reported?
(19) A: As I recall, yes.
(20) Q: Do you have any knowledge at all about
(21) the - as to the area that this spill affected?
(22) A: Yes.
(23) Q: And what is - what is the basis of that
(24) knowledge?
(25) A: Well, I am Texas Land Commissioner and I

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(1) am responsible for managing the submerged lands of
(2) Texas. And this land was a combination of adjacent
(3) land to submerged lands and submerged lands of
(4) Texas.
(5) Q: All right.
(6) A: And, you know, the fact is these are
(7) very sensitive bay areas. And as I recall, I
(8) remember reading some Corpus Christi news accounts
(9) that went into great detail about how sensitive
(10) these areas were.
(11) Q: Well, when you're talking about
(12) sensitive areas, what do you mean? In what regard?
(13) A: Bays tend to be - bays and estuaries
(14) are the nursery grounds for the Gulf of Mexico. It
(15) all starts in the bays and estuaries.
(16) Q: When you talk about an estuary, what are
(17) you talking about?
(18) A: An estuary is a submerged area that is a
(19) part of the bay system and the river system. It
(20) tends to be shallow, a combination of salt water
(21) and fresh water, and there is where the shrimp and
(22) the start of the food chain occurs, and a lot of
(23) the smaller fish that eventually turn out to be
(24) very large fish in the gulf, start their lives.
(25) Q: Okay.

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(1) A: Remember, I'm a marketing major and have
(2) a law degree, so I don't have -
(3) MR. McCULLY: We'll remind him of
(4) that, I'm sure.
(5) MR. EDWARDS: I pass the witness.
(6) EXAMINATION
(7) BY MR. McCULLY:
(8) Q: Commissioner, as I mentioned before we
(9) began my name is Robert McCully, I'm an attorney
(10) with Koch representing the defendants in this
(11) matter. And I have met you once before, sir. I
(12) was at that meeting in your office in 1995.
(13) A: Did I describe it correctly?
(14) I was the lawyer from headquarters.
(15) We'll talk about that.
(16) I don't think the question was asked
(17) - if it was I apologize - do you recall when that
(18) meeting was held?
(19) A: No.
(20) Q: Okay.
(21) If I were to say January, 1995, would
(22) that bring or cause you to recall the date of that
(23) meeting?
(24) A: That would sound right me.
(25) Q: It would not?

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(1) A: It would sound right to me. I wrote
(2) this letter December 5th. My guess is - I can't
(3) recall - with Christmas, January would be the
(4) quickest y'all could get ...
(5) Q: Okay. I think you testified beyond the
(6) local person here, and a lawyer, you weren't
(7) familiar with anyone else who was at that meeting?
(8) A: No. I mean, I was familiar with them.
(9) I just can't recall who - you realize I have
(10) thousands of meetings.
(11) Q: I understand.
(12) Do you recall Jim Simmons being at
(13) that meeting?
(14) A: Who is Jim Simmons?
(15) Q: Okay. I guess the answer to that
(16) question is probably no, then?
(17) A: If you tell me who he is.
(18) Q: Jim Simmons is the Division manager for
(19) south Texas.
(20) A: As I recall there were three of you guys
(21) there. There was a lawyer, there was a lobbyist,
(22) and somebody from - you said division, but, you
(23) know, I think of a guy where the rubber meets the
(24) road, the lawyer and the lobbyist. There could
(25) have been a fourth person. That's just what I

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(1) remember.
(2) Q: Do you remember who the person who
(3) you're referring to as a lobbyist was?
(4) A: No. Somebody - subsequently,
(5) I talked to him once or twice about other issues,
(6) but I think - after the meeting, I think I looked
(7) him up and they have a little book that has
(8) registered lobbyists in it.
(9) Q: That was my next question. When you
(10) referred to him as a lobbyist, are you saying that
(11) he's registered with the State of Texas as a
(12) lobbyist?
(13) A: I think so. If you can you remind me
(14) who it is, maybe I can tell you.
(15) Q: I believe the individual's name was Bill
(16) Oswald?
(17) A: I think that's the registered lobbyist
(18) here. I mean, once again, it's all public
(19) information.
(20) Q: Beyond that meeting, was there any
(21) additional follow-up to your December 5th letter to
(22) Koch from your office?
(23) A: I don't think from - directly from my
(24) office, no, regarding the meeting.
(25) Q: Okay. Was there any further enforcement

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Garry Mauro
December 15, 1997

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[1] 7. ____/____ Now Reads: ____
[2] Should read: ____
[3] Reason for Change: ____
[4] 8. ____/____ Now Reads: ____
[5] Should read: ____
[6] Reason for Change: ____
[7] 9. ____/____ Now Reads: ____
[8] Should read: ____
[9] Reason for Change: ____
[10] I, GARRY MAURO, have read the foregoing
[11] deposition and affix my signature that same is true
[12] and correct, except as noted herein.
[13]
[14]
[15] GARRY MAURO
[16] THE STATE OF ____)
[17] COUNTY OF ____)
[18] SUBSCRIBED AND SWORN to before me
[19] by the said witness, GARRY MAURO, on this the ____
[20] day of ____, 1997.
[21]
[22]
[23] Notary Public in and for
The State of ____
[24] JOB NO. 5055
[25]

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[1] COUNTY OF TRAVIS)
CAUSE NO. 94-6629-H
[2] STATE OF TEXAS)
[3] I, Deborah L. Fitzpatrick, Certified
[4] Shorthand Reporter in and for the State of Texas,
[5] do hereby certify that the witness, GARRY MAURO,
[6] was sworn by me; that the foregoing pages are a
[7] true and correct transcript of the proceedings had
[8] before me on the 15th of December, 1997.
[9] Further certification requirements
[10] pursuant to the Rules 205 and 206 will be certified
[11] to after they have occurred.
[12] This ____ day of ____, 1997.
[13]
[14] Deborah L. Fitzpatrick, CSR 7151
400 W. 15th St., Suite 408
Austin, Texas 78701
[15]
[16]
[17] CERTIFICATION PURSUANT TO 205 AND 206
[18] \$ ____ is the charge for the
[19] preparation of the completed oral deposition
[20] transcript and any copies of exhibits, charged to
[21] Plaintiffs;
[22] That the original deposition transcript was
[23] submitted by Certified Mail/Hand Delivery on the
[24] ____ day of ____, 1997, to the counsel for
[25]

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[1] the Witness for examination, signature and return
[2] to Fredericks-Carroll Reporting & Litigation
[3] Services, Inc.
[4] That the deposition transcript ____ was
[5] ____ was not returned to the deposition officer on
[6] the ____ day of ____, 1997, and if
[7] returned, the attached Errata Sheet contains
[8] changes, if any, and the reasons therefor, made by
[9] the witness;
[10] That the original deposition transcript, or
[11] a certified copy thereof, together with copies of
[12] all exhibits, was delivered to the attorney or
[13] party who asked the first question appearing in the
[14] transcript.
[15] That a copy of this certificate was served
[16] on all parties shown herein.
[17]
[18]
[19] Deborah L. Fitzpatrick, CSR 7151
[20] Expiration 12/31/99
[21] Fredericks-Carroll Reporting
& Litigation Services, Inc.
[22] 400 W. 15th Street, Suite 408
Austin, Texas 78701
[23] Phone: (512) 477-9911 - (800) 234-3376
Fax: (512) 477-9919
[24] JOB NO. 5055
[25]

Page 73

[1] STIPULATIONS
[2] DEPOSITION(S) OF Garry Mauro
[3]
[4] TAKEN ON December 15, 1997 BY Deborah Fitzpatrick
[5] 1. THIS DEPOSITION IS TAKEN PURSUANT TO:
____ (a.) Notice
[6] ☒ (b.) Notice and Subpoena
____ (c.) Agreement
[7] ____ (d.) Court Order
[8] 2. OBJECTIONS:
____ (a.) Objections will be made
[9] pursuant to the Texas/Federal Rules of Civil
Procedure.
[10] ____ (b.) All objections will be made at
the time of taking of the deposition.
[11] ____ (c.) All objections are reserved.
____ (d.) Other: ____
[12]
[13] 3. SIGNATURE AND DELIVERY:
[14] ☒ (a.) The original transcript will be
submitted to ____ the witness or ☒ the
witness' attorney, who will forward the signed
deposition, including any changes made, to
[15] Fredericks-Carroll Court Reporters within
____ 21 ____ days of submission.
[16]
____ (b.) Signature is waived and the
[17] reporter will deliver the original transcript
and exhibits to the Custodial Attorney.
[18]
____ (c.) The original transcript will
[19] remain in the court reporter's office for
signature for ____ days from date of
[20] submission.
[21] ____ (d.) The original signature page,
along with a copy of transcript, will be
[22] submitted to ____ for
submission to the witness for signature, and
[23] thereafter will forward the executed signature
page, along with any changes made, within
[24] days to the offices of Fredericks-Carroll
Court Reporters for inclusion in the original
[25] transcript.

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RICHARD TUTTLE

Condenseit!

December 13, 1997

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NO. 94-6629-B
IN THE DISTRICT COURT
OF THE STATE OF TEXAS
JUDICIAL DISTRICT
347TH JUDICIAL DISTRICT
VS.
Koch Catering Systems,
Inc.; David Fockham;
and Richard Tuttle

DEPOSITION OF RICHARD TUTTLE
TAKEN ON DECEMBER 10, 1997

APPEARANCES:

COUNSEL FOR THE PLAINTIFFS:

MS. CAROL V. GILDEN
MR. STEVEN A. KAMMER
Koch Spill Control, P.C.
200 N. LaSalle, Suite 2100
Chicago, Illinois 60601-1895

COUNSEL FOR THE DEFENDANTS:

MR. RUSSELL HANNING
Messers, Hanning, Manning
& Ward, P.C.
711 N. Carancahua, Suite 1010
Corpus Christi, Texas 78402

ALSO PRESENT: MS. SALLY MOFFETT
REPORTED BY: JENNIFER L. KARL, CSR
(ORIGINAL)

Deposition and answers of RICHARD TUTTLE, who resides in Nueces County, Texas, taken herein by the counsel for the Plaintiffs, before JENNIFER L. KARL, a Certified Court Reporter in and for the State of Texas, on the 18th day of December, 1997 between the hours of 10:30 a.m. and 5:30 p.m., in the offices of Edwards, Terry & Edwards, 802 N. Carancahua, Suite 1400, Corpus Christi, Texas in accordance with the Texas Rules of Civil Procedure and the agreements hereinafter set forth.

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RICHARD TUTTLE,
having been first duly cautioned and sworn upon his oath to tell the truth, the whole truth, and nothing but the truth, testified as follows:

EXAMINATION

BY MS. GILDEN:

Q. Good morning, Mr. Tuttle. My name is Carol Gilden. I am one of the plaintiffs' attorneys in this case. Will you please state your full name for the record.

A. It's Richard D. Tuttle.

Q. And, Mr. Tuttle, where is your home address?

A. 461 Sharon Drive.

Q. And what is your business address?

A. It's Post Office Box 8, Corpus Christi, Texas.

Q. Are you currently employed?

A. Yes.

Q. And who are you currently employed by?

A. Koch Industries.

Q. And how long have you been employed by Koch Industries?

A. It will be seven years in January.

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Page 3

Q. What was your position at Koch Industries when you first started working for the company?

A. I was the Director of Corporate Communications.

Q. And who did you report to?

A. I reported to Richard Fink, Vice-president of Government and Public Affairs.

Q. And how long did you serve as the Director of Corporate Communications?

A. That was about 18, about 18 months.

Q. During the period you served as Director of Corporate Communications, did anyone report to you?

A. One person. Her name is Kim Carraway.

Q. And how do you spell Carraway?

A. C-A-R-R-A-W-A-Y.

Q. Did your position change after 18 months?

A. Uh-huh.

Q. What did your position change to?

A. I became Regional Public Affairs Director based in Corpus Christi. That would have been September of 1992.

Q. And how long did you serve as Regional Public Affairs Director?

A. I'm currently in that position.

Q. What were your duties and responsibilities

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1 A. Yes, I do.
2 Q. Does 1300 at the top of the page refer to
3 the time of the day?
4 A. I would assume that would be correct, as
5 well.
6 Q. Okay. Underneath the heading at the bottom
7 of the page that we just looked at, the first line
8 reads, "Recover to refinery 302 net barrels"?
9 A. Uh-huh.
10 Q. What does that refer to, if you know?
11 A. That would be oil that was trucked back to
12 the Koch Refining system for processing.
13 Q. We're done with Tuttle Exhibit No. 9.
14 A. Oh, okay.
15 Q. Just so you know, you can put that one
16 down.
17 A. Okay.
18 Q. Mr. Tuttle, on October 17th, 1994, did you
19 tell a reporter from Channel 3 the following: Quote,
20 "We've been assessing the volume of the spill over
21 the weekend and kind of verifying these numbers. We
22 believe now that about 2100 barrels was involved"?
23 A. Yes.
24 Q. You made that statement?
25 A. Yes, I did.

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1 Q. What personal knowledge did you have that
2 approximately 2100 barrels was involved?
3 A. Again, it was based on information provided
4 at the incident command center, the joint command,
5 doing the assessment of the situation. I had no
6 personal knowledge. That was based on what I was
7 given.
8 Q. Who made the statement about the 2100
9 barrels of oil being involved at the command center?
10 A. I can't recall who that was.
11 Q. Was it Mr. Simmons?
12 A. Again, I can't recall specifically who that
13 would have been.
14 Q. During the time period from October 10th
15 through October 17th, did you ever speak to
16 Mr. Simmons personally and attempt to get a better
17 estimate of the number of barrels of oil that were
18 spilled from him?
19 A. At times I did request an update, and the
20 response was that they were continuing to work on
21 that number.
22 Q. So Mr. Simmons never gave you an actual
23 number that he believed had been spilled?
24 A. I didn't get it. No, I did not get specific
25 numbers.

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1 Q. He told you that they were working on an
2 update, but he did not give you numbers?
3 A. Exactly, that's correct.
4 Q. During the period from October 10th through
5 October 17th, did you talk with any Koch attorneys?
6 A. The only attorney was Vince McLickly, and
7 that was related to the Ocean Drive. He was on a
8 team to go knocking on doors and talking to
9 homeowners about problems that they had related to
10 the oil spill and that was -- other than that, that
11 was the only attorney I spoke to.
12 Q. Was Allan Hallick at the incident command
13 center at all?
14 A. Yes, he was.
15 Q. Was he at the incident command center every
16 day?
17 A. He would be there and leave. I don't know
18 exactly what his schedule was, but he would, he would
19 come and go.
20 Q. Did you ever --
21 MS. GILDEN: Strike that.
22 Q. (BY MS. GILDEN) Did you ever have any
23 conversations with Mr. Hallick?
24 A. I may have. I can't recall at this point.
25 Q. During the time period from October 10th

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1 through October 17th, did you talk to anyone at
2 Wichita concerning the Gum Hollow spill?
3 A. There was someone from our group who came to
4 relieve me, Kim Carraway, and she had some
5 involvement in the media during that period, so that
6 would have been the contact that I had with Wichita.
7 Q. What do you mean she came to relieve you?
8 A. Well, after three days, I needed to sleep,
9 and so she came and was handling some of the media
10 work for about a day, a day and a half and then went
11 back to Wichita.
12 Q. Now, when you say she was handling some of
13 the media work, what was she doing?
14 A. Making statements to the media, updates.
15 Q. Was she preparing releases?
16 A. No.
17 Q. Was she talking to TV reporters?
18 A. Not that I recall.
19 Q. Was she talking to radio reporters?
20 A. That's possible.
21 Q. How about newspaper reporters?
22 A. I believe newspaper reporters, she did talk
23 to newspaper reporters.
24 Q. Did you have any discussions with her as to
25 what she should tell these reporters?

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1 A. Again, it was based on information that we
2 had developed at the briefing center.
3 Q. So the answer is yes, you had discussions
4 with her?
5 A. Yes.
6 Q. And you told her what to say?
7 A. No, I did not tell her what to say. She had
8 access to the same information I had and was using
9 that to make statements.
10 Q. Did you have any discussions with her as to
11 the type of statements she should make?
12 A. No.
13 Q. The subjects of the statements?
14 A. No.
15 Q. What you had told other reporters?
16 A. She was aware of that.
17 Q. And how was she aware of that?
18 A. Well, I told her, plus she had access to all
19 of the media coverage that had been in print. She
20 had the newspaper articles and the TV coverage, as
21 well.
22 Q. Did you talk to any other individual from
23 Wichita regarding the Gum Hollow spill during the
24 same period of time, October 10th through October
25 17th?

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1 A. Yes, Riff Yeager. I did talk to Riff Yeager
2 by phone a number of times, who was the Director of
3 Corporate Communications.
4 Q. And was anyone else on the phone during
5 these conversations?
6 A. I believe at one point there were a couple
7 of other individuals, one from the pipeline operation
8 and I think another -- there was another attorney on
9 the phone conversation.
10 Q. Did you say pipeline information?
11 A. Pipeline management.
12 Q. Oh, I'm sorry.
13 A. Management of the pipeline.
14 Q. And you said there was one other attorney?
15 A. Right.
16 Q. About how many phone conversations did you
17 have with Riff Yeager?
18 A. No more than three.
19 Q. So approximately three?
20 A. Correct.
21 Q. And how long did these conversations last?
22 A. Five to maximum ten minutes, 15 minutes, I
23 guess, at the most.
24 Q. What did you tell Riff Yeager, and to the
25 extent others were present that you spoke to him

December 18, 1997

Condenset!™

RICHARD TUTTLE

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1 speaking at the press conference?
 2 A. Yes, I did.
 3 Q. Did you use anything else at the press
 4 conference?
 5 A. Not to my recollection.
 6 Q. So the answer is no, you didn't use anything
 7 else to aid you for speaking at the press conference?
 8 A. That's correct.
 9 Q. Who prepared the document contained in
 10 Exhibit No. 10?
 11 A. To the best of my knowledge, I prepared it
 12 with input from the GLO and the Coast Guard. They
 13 approved the language in this. It was jointly
 14 released, as you can see.
 15 Q. Who approved the language?
 16 A. The individuals listed here, Montoya from
 17 the Coast Guard and Lugo with the GLO, and obviously
 18 I was involved in our public affairs group.
 19 Q. So let me see if I understand this right.
 20 You drafted the release; you showed it to
 21 Mr. Montoya --
 22 A. Montoya and Lugo. They got it by fax. And
 23 this was in preparation for a press conference, is my
 24 recollection on that date, which I believe was a
 25 Tuesday. I don't recall, but I think so.

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1 Q. Do you recall whether they had any comments
 2 on the press release draft that you sent to them?
 3 A. I don't believe they had any real changes,
 4 based upon my recollection. There might have been a
 5 few, but I don't recall. I just don't recall.
 6 Q. Now, I'd like to direct your attention to
 7 the second paragraph of the release --
 8 A. Uh-huh.
 9 Q. -- which reads, "Revised estimate of the
 10 spill has been set at 2151 barrels of oil?"
 11 A. Right.
 12 Q. "The earlier estimate was based on the
 13 visible amount of crude on the water and did not
 14 include an evaporation factor as well as other
 15 preliminary data and information available to Koch
 16 industries?"
 17 A. Right.
 18 Q. Do you see that language?
 19 A. Yes, I do.
 20 Q. What other preliminary data and information
 21 available to Koch Industries were you referring to?
 22 A. Again, that was based on preliminary data
 23 that was made available at the briefing center at the
 24 Coast Guard building, based on an assessment. I
 25 mean, I don't have any personal knowledge of what

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1 else that would be.
 2 Q. You don't recall or know what the data
 3 itself was?
 4 A. No, no. Again, it was a constant process of
 5 trying to calculate that; but I wasn't involved in
 6 that at all. I had nothing to do with the
 7 calculations.
 8 Q. Now, there's a reference to an evaporation
 9 factor. What is that?
 10 A. It goes up in the air. The sun comes out,
 11 heats up and goes up in the air, evaporates. I'm not
 12 an engineer, but that's my simple way of saying it.
 13 Q. Now, did someone from Koch tell you that the
 14 evaporation factor was taken into account in coming
 15 up with an estimate?
 16 A. It was a combination of Koch and, again,
 17 the Coast Guard. I think the Coast Guard may have
 18 actually had some formula they were using, and I
 19 think the 50 percent may have been a Coast Guard
 20 calculation. Again, I don't recollect how that was
 21 formed.
 22 Q. Now, who at Koch did you talk to in
 23 connection with your preparation of this release?
 24 A. It would have been, again, Riff Yeager in
 25 our communications group in drafting the statement.

1 Q. Who gave you the language contained in the
 2 second sentence in the second paragraph of this
 3 release?
 4 A. This, again, language that was provided at
 5 the command center that I, in the briefings,
 6 extracted and used to form that language. I mean, I
 7 didn't have knowledge myself to do that. I had to --
 8 I had been given that information.
 9 Q. I'd like to direct your attention to the
 10 final paragraph on Tuttle Exhibit No. 10. And it
 11 reads, "The spill occurred Saturday October 8 during
 12 what was believed to have been a lightening strike
 13 that hit a pump station causing a Koch pipeline to
 14 rupture." Do you see that?
 15 A. Yes, I do.
 16 Q. What personal knowledge do you have as to
 17 what the cause of the rupture was at the point in
 18 time that the October 18th release was prepared?
 19 A. Once again, I had no personal knowledge of
 20 that. It was based on information given to me.
 21 Q. So you don't know whether or not this is an
 22 accurate statement, do you?
 23 A. I trust that it is.
 24 Q. But you don't actually know?
 25 A. I don't actually know. I was not there to

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1 see it. I mean, I --
 2 Q. So you don't actually know whether or not,
 3 in fact, the statement in here as to the cause of the
 4 rupture was, in fact, true or not?
 5 A. Again, my information is that it's true, but
 6 I have -- I don't have personal knowledge that that's
 7 true.
 8 Q. So you don't have personal knowledge as to
 9 whether or not that statement in the last paragraph
 10 of the release on the 18th is true?
 11 A. That's correct, because the information was
 12 provided to me.
 13 Q. Okay. And that was information provided to
 14 you by who?
 15 A. Well, I mean, it goes back to the
 16 initial --
 17 Q. The initial conversations that we've
 18 discussed earlier?
 19 A. That's correct.
 20 Q. Okay. All right. Mr. Tuttle, on -- we're
 21 done with that exhibit for now.
 22 A. Okay.
 23 MR. MANNING: Good. Break time.
 24 (A break was taken.)
 25 Q. (BY MS. GILDEN) Mr. Tuttle, on October

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1 18th, 1994 did you tell a reporter from Channel 10
 2 the following, "Companies have planned for these type
 3 of events with drills and exercises, but the fact is
 4 sometimes the actual event is the best teacher and
 5 can be a pretty good teacher, but it's something you
 6 don't want to experience very often, either?"
 7 A. Yes, I said that.
 8 Q. And were you saying that Koch had
 9 contingency plans and that these contingency plans
 10 adequately met the circumstances that unfolded in the
 11 Gum Hollow oil spill?
 12 A. Uh-huh, yes.
 13 MS. GILDEN: Would you please mark this
 14 as --
 15 THE REPORTER: 11.
 16 MS. GILDEN: Yes.
 17 (Deposition Exhibit No. 11
 18 was marked for identification.)
 19 Q. (BY MS. GILDEN) And if you'd take a moment
 20 to review what's been marked as Tuttle Exhibit
 21 No. 11.
 22 A. (The witness complies.)
 23 Q. Mr. Tuttle, do you recognize the documents
 24 contained in Tuttle Exhibit No. 11?
 25 A. Yes, I've seen this.

RICHARD TUTTLE

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1 A. Okay.
2 Q. And, in particular, I would like you to take
3 a look at the pages with the Bates stamp number.
4 It's about the first quarter of the document through,
5 085601.
6 A. Okay. All right.
7 Q. I would like you to take a moment just to
8 glance through 5601 through 5604.
9 A. Okay.
10 Q. Are you familiar with the guidelines that
11 are reflected on the pages with the Bates stamp
12 numbers KW-EHS-085601 - 5604?
13 A. Those two pages in specifics?
14 Q. 5601 through 5604.
15 A. Okay. I am not familiar with any of those.
16 That's -- I don't know if I have actually ever seen
17 that before. I wasn't even employed by Koch when
18 these were developed.
19 Q. However, they are included in a document --
20 A. Right.
21 Q. -- dated August 22nd, 1991?
22 A. Right. I don't have specific knowledge of
23 these.
24 Q. Okay.
25 MS. GILDEN: This is off the record.

1
2
3
4
5
6
7 RICHARD TUTTLE
8
9
10 THE STATE OF TEXAS:
11 COUNTY OF NUECES:
12
13 Subscribed and sworn to before me by the said
14 witness, RICHARD TUTTLE, on this the ____ day of
15 _____, 1998.

Notary Public, State of Texas

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1 (Off the record.)
2 Q. (BY MS. GILDEN) Mr. Tuttle, I just have a
3 few more questions. I would like to direct your
4 attention back to Exhibit No. 12, which is still in
5 front of you, your supplemental answers. And if you
6 would turn to Page 3, Interrogatory No. 4 asks you to
7 identify each meeting you attended at which prior or
8 future communications to any local or national news
9 media relating to the pipeline rupture that occurred
10 on or about October 8, 1994, near Gum Hollow Creek,
11 Texas, which is the subject of this lawsuit was
12 discussed. And I would like to turn your attention
13 to the next page, Page 4 at the top. There is a
14 listing of press briefings, press conferences. Now,
15 we already talked a little bit about some of these.
16 A. Right.
17 Q. What I would like to know is whether you
18 spoke at each press briefing or conference identified
19 in your answer to Interrogatory --
20 A. Yes.
21 Q. Let me finish my question. In answer to --
22 MS. GILDEN: Would you read back the
23 question? I am sorry. I lost my train of thought.
24 (The pending question was read back by the reporter.)
25 Q. (BY MS. GILDEN) No. 4?

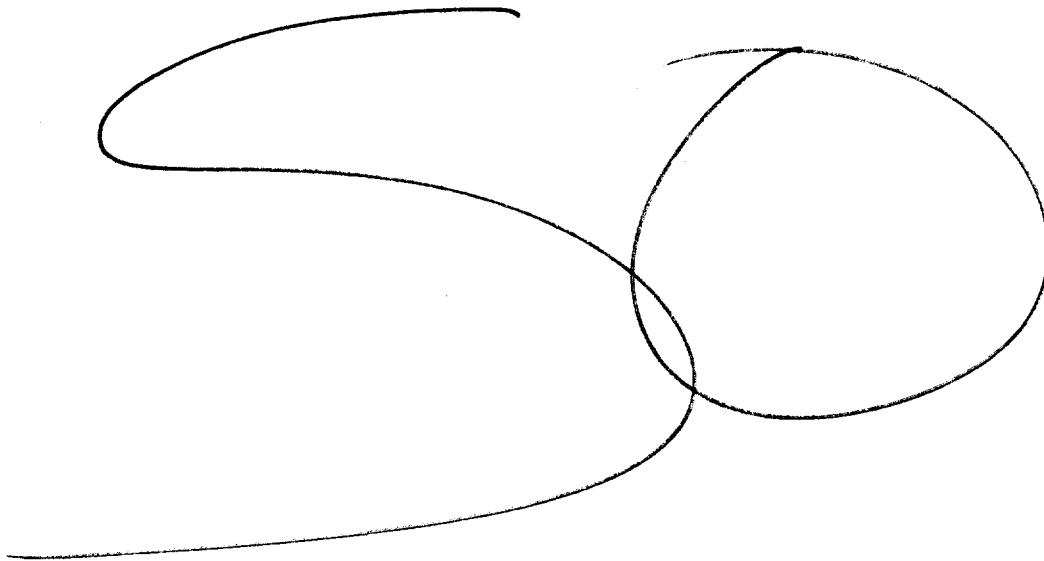
1 NO. 04-6529-M
2 KEVIN HARMON * IN THE DISTRICT COURT
3 DAVID FANCHER *
4 WILLIAM COMPTON *
5 ROMEO GARZA GARZA *
6 WILLIAM CORANATO *
7 PETER S. GONZALES *
8 JANE STUBBS * AND ON
9 BEHALF OF ALL OTHERS * 34TH JUDICIAL DISTRICT
10 SIMILARLY SITUATED *
11 VS. *
12 KOCH GATHERING SYSTEMS, *
13 INC.; DAVID FODERMAN *
14 AND RICHARD TUTTLE * NUECES COUNTY, TEXAS
15
16 CERTIFICATE FOR THE
17 DEPOSITION OF RICHARD TUTTLE
18 TAKEN ON DECEMBER 18, 1997
19 I, JENNIFER L. KARR, Certified Court Reporter in and
20 for the State of Texas, hereby certify pursuant to
21 the Rules and/or agreement of the parties present to
22 the following:
23 That this deposition transcript is a true record of
24 the testimony given by the witness named herein
25 after said witness had duly sworn/affirmed by me.
26 That _____ is the charge for the preparation of
27 the deposition transcript and any copies of
28 exhibits, charged to MS. CAROL GILDEN.
29 That the deposition transcript was submitted on
30 December 30, 1997 to MR. RUSSELL MANNING for the
31 witness to examine, sign and return to ALAN
32 KOPPELMAN, Inc. by January 15, 1998. The attached
33 "Certificate" shall contain any changes and the
34 reasons therefor, made by the witness.
35 That the deposition transcript was returned to the
36 deposition officer on _____ or the
37 deposition transcript was not returned by the
38 stipulated date for the following reason:
39 _____
40 _____
41 _____

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1 A. Yes, I did.
2 Q. And is it your testimony that you used the
3 press releases that you prepared to aid you in
4 speaking at these conferences and briefings?
5 A. Yes, I did.
6 Q. Other than the two pages of notes that you
7 identified during your testimony here today that were
8 written by you and the press releases that you
9 prepared or were involved in preparing, did you use
10 any other information for purposes of speaking,
11 written information, for purposes of speaking at
12 these press briefs and conferences?
13 A. Not to my recollection.
14 MS. GILDEN: Okay. I have no further
15 questions at this time. Do you have any questions,
16 Counsel, that you would like to ask?
17 MR. MANNING: Thank you. But we will
18 reserve our questions for the time of trial or
19 hearing.
20 MS. GILDEN: And with that, let's go
21 off the record at 5:25.
22 (The deposition concluded at 5:30 p.m.)
23
24
25

1 That the original deposition, or a copy thereof in
2 the event the original was not returned to the
3 officer, together with copies of all exhibits, is in
4 the possession and custody of MS. CAROL GILDEN as the
5 confidential attorney and was delivered on _____
6 That pursuant to information made a part of the
7 record at the time said testimony was taken, the
8 following includes all parties of record.
9 MR. WILLIAM B. EDWARDS, MR. VERNON M. BEASER,
10 MR. STEVEN A. KANNER, MR. CHARLES KIPPLE,
11 MR. JOEL C. KEBERTIN, MR. ANTHONY D. SHAFER,
12 MR. LOUISE D. CARROLL, MR. THOMAS R. BELL and
13 MS. CAROL A. BERENSONFIELD
14 Attorneys for Plaintiffs
15 MR. ROBERT MACIELLY, MR. GENE E. WARD and
16 MR. KENT E. WESTERLAND
17 Attorneys for Defendants
18 That a copy of this certificate was served on all
19 parties above named.
20 Subscribed and sworn to on this the 30th day of
21 December, 1997.
22
23
24
25 JENNIFER L. KARR
Certified Court Reporter
Certification Number: 2061
Date of Expiration: 12/31/98
Business Address:
AK/RET REPORTING, INC.
850 Tower II
Corpus Christi, Texas 78478

A handwritten mark or signature consisting of a single continuous line. It starts with a horizontal stroke from the left, curves upwards and to the right to form a large loop, then crosses itself and continues with a long, sweeping horizontal stroke to the left.

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

UNITED STATES OF AMERICA, ET AL.)

Plaintiffs,)

v.)

KOCH INDUSTRIES, INC., ET AL.)

Defendants.)

CIVIL ACTION NO. H-95-1118

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
ENTERED

MAR - 7 2000

Michael N. Milby, Clerk

CONSENT DECREE

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1. BACKGROUND

Whereas, on April 17, 1995, the United States, at the request of the United States Environmental Protection Agency and the U.S. Coast Guard, filed this civil action against Defendants Koch Industries, Inc. et al. pursuant to the Clean Water Act, 33 U.S.C. § 1251 et seq. ("CWA"), as amended by the Oil Pollution Act of 1990, Pub. L. 101-380, 104 Stat. 484 ("OPA"), seeking injunctive relief and civil penalties for the discharge of crude oil and petroleum products into navigable waters or adjoining shorelines of the United States;

Whereas, on February 11, 1997, the State of Texas, at the request of the General Land Office of Texas, filed a complaint in intervention in this action against Defendants Koch Industries, Inc. et al. pursuant to the CWA, as amended by OPA, seeking injunctive relief and civil penalties for the discharge of crude oil and petroleum products into navigable waters or adjoining shorelines of the United States in Texas and in other areas in Texas;

Whereas, on July 28, 1997, the United States, at the request of the United States Environmental Protection Agency and the U.S. Coast Guard, filed Civil Action No. 97-CV687B(W) in the Northern District of Oklahoma against Defendants, Koch Industries, Inc. et al. pursuant to the CWA, as amended by OPA, seeking injunctive relief and civil penalties for the discharge of crude oil and petroleum products into navigable waters or adjoining shorelines of the United States;

Whereas, on November 3, 1997, the State of Texas, at the request of the Railroad Commission of Texas, filed a complaint in intervention in Civil Action No. 97-CV687B(W) in the Northern District of Oklahoma against Defendants Koch Industries, Inc. et al. pursuant to the CWA, as amended by OPA, seeking injunctive relief and civil penalties for the discharge of crude oil and petroleum products into navigable waters or adjoining shorelines of the United States in Texas and other areas in Texas, and in its

January 26, 1998 amended complaint, seeking injunctive relief and penalties for violations of § 85.381 of the Texas Natural Resources Code;

Whereas, the Defendants have disputed issues regarding, among other things, the jurisdictional reach of the CWA, as amended by OPA, the quantities of discharged material, and the proper measure of any civil penalty or injunctive relief to be assessed with regard to the discharge events at issue, and contend that they have already taken good faith steps to clean up discharges and to substantially reduce the number of discharges occurring from their crude oil and refined products pipelines;

Whereas the Plaintiffs and Defendants in these two actions have engaged in lengthy and protracted litigation and now seek to settle these matters amicably without further litigation;

Whereas, the Defendants, by entering into this Consent Decree, do not admit any liability to Plaintiffs arising out of the transactions or occurrences alleged in any of the complaints; and,

Whereas, the Parties to this Consent Decree desire to resolve this matter and the related matter pending in the U.S. District Court for the Northern District of Oklahoma, Civil Action No. 97-CV687B(W), without further litigation, and agree to do so through the entry of the following Consent Decree, and this Court finds by entering this Consent Decree, that the Parties have negotiated this Consent Decree in good faith, and that the settlement embodied by this Consent Decree is fair, reasonable, and in the public interest:

THEREFORE, with the consent of the Parties to this Consent Decree, it is ORDERED, ADJUDGED, AND DECREED:

II. JURISDICTION AND VENUE

1. This Court has jurisdiction over the Parties and venue is proper in this Court. The parties agree

to the entry of this Consent Decree by this Court.

III. PARTIES BOUND

2. This Consent Decree applies to and is binding upon the United States, the State of Texas, and the Defendants. Any change in ownership of the Defendants or corporate status of the Defendants shall in no way alter the Defendants' responsibilities under this Consent Decree.

IV. DEFINITIONS

3. Unless otherwise expressly provided herein, the terms used in this Consent Decree shall have the meaning assigned to them in the CWA, as amended by the OPA, or in such regulations promulgated thereunder. Whenever the terms defined below are used in this Consent Decree or in the Appendices attached hereto and incorporated hereunder, the following definitions shall apply:

a. "Affiliated" shall mean directly, or indirectly through one or more intermediaries, controlling of, or controlled by, or under common control with.

b. "API Provisions" shall mean those provisions set forth by the American Petroleum Institute pertaining to the construction, maintenance, and/or operation of crude oil and refined petroleum product pipelines.

c. "ASME Provisions" shall mean the provisions set forth by the American Society of Mechanical Engineers pertaining to the construction, maintenance, and/or operation of crude oil and refined petroleum product pipelines.

d. "Consent Decree" shall mean this written agreement and all Appendices attached hereto and any modifications of the agreement or the Appendices.

e. "Day" shall mean a calendar day unless the Consent Decree expressly refers to a Working Day.

"Working Day" shall mean a day other than a Saturday, Sunday, or Federal or State of Texas holiday. In computing any period of time under this Consent Decree, where the last day would fall on a Saturday, Sunday or Federal or State of Texas holiday, the period shall run until the close of business of the next Working Day.

f. "Defendants" shall mean Koch Industries, Inc., Koch Oil Company, Koch Pipeline Company, L.P., Koch Gathering Systems, Inc., Koch Refining Company, L.P., Koch Service, Inc., Koch Materials Company, Chase Pipe Line Company, Bow Pipe Line Company, Citronelle Pipeline Co., their affiliated assigns, and their affiliated successors.

g. "DOT" shall mean the U.S. Department of Transportation and any successor departments or agencies.

h. "Discharge" shall have the same meaning as in Section 2701(7) of the OPA, meaning any emission (other than natural seepage), intentional or unintentional, and includes spilling, leaking, pumping, pouring, emitting, emptying, or dumping.

i. "EPA" shall mean the United States Environmental Protection Agency and any successor departments or agencies.

j. "NACE Provisions" shall mean the provisions set forth by the National Association of Corrosion Engineers pertaining to the construction, maintenance, and/or operation of crude oil and refined petroleum product pipelines.

k. "Paragraph" shall mean a portion of this Consent Decree identified by an arabic numeral.

l. "Plaintiffs" shall mean the United States on behalf of the U.S. Coast Guard and EPA, and the

State of Texas.

- m. "Parties" shall mean the United States of America, the State of Texas, and the Defendants.
- n. "Responsible Official of the Defendants" shall mean any officer of the Defendants who is in charge of a principal business function, or any other person who performs similar decision making functions for the Defendants, or a person named in a certificate of delegation which designates the authority of that individual to sign documents which binds the Defendants to the terms of such documents.
- o. "Section" shall mean a portion of this Consent Decree identified by a roman numeral.
- p. "Sound Industry Practice" shall mean practice consistent with reasonable and prudent operations in the industry, including, as applicable, compliance with API Provisions, NACE Provisions, ASME Provisions, and company standards.
- q. "United States " shall mean the United States of America.
- r. "U.S. Coast Guard" shall mean the United States Coast Guard and any successor entities.

V. GENERAL PROVISIONS

- 4. This Consent Decree resolves Plaintiffs' claims against Defendants for civil penalties and injunctive relief (except any claims for cleanups regarding the settled discharges) arising (1) from the discharges set forth in the complaints and any amended complaints in this civil action and Civil Action No. 97CV697B(W) in the Northern District of Oklahoma and (2) from the additional discharges identified in Appendix A hereto. The Parties agree to bear their own legal costs, fees (including attorney and expert witness fees), and expenses incurred as a result of the subject civil actions. This Consent Decree shall not constitute any admission for any purpose by any of Defendants or Plaintiffs as to each other or any third party.
- 5. Compliance with Applicable Law: Except as expressly provided herein, nothing in this Consent

Decree shall in any way excuse Defendants from their obligation to comply with the requirements of all Federal, State, or local laws, permits, and regulations. In particular, nothing in this Consent Decree relieves Defendants from the duty to comply with, or changes the requirements of, the pipeline safety law, 49 U.S.C. § 60101 et seq., the pipeline safety standards adopted under that law (49 C.F.R. Parts 190-199), or applicable orders issued by DOT under that law.

6. The obligations of Defendants under Section VII (Operating Requirements) of this Consent Decree shall remain in effect for a period of three (3) years from the Effective Date of the Consent Decree; provided, however, that with regard separately to each plan put forward by Defendants under Section VII (Operating Requirements), the obligations with regard to that plan shall remain in effect either until the expiration of the foregoing three-year period or the expiration of 24 months following the implementation of the plan by Defendants, whichever period expires last. Within thirty (30) days of implementation of each plan, Defendants shall provide Plaintiffs with written notice of the date of such implementation.

VI. PAYMENT OF CIVIL PENALTIES

7. To resolve Federal and State-law claims as provided for herein, within thirty (30) days of entry of this Consent Decree, Defendants shall pay to Plaintiffs a civil penalty of thirty million dollars (\$30,000,000). Of this amount, Defendants shall pay fifteen million dollars (\$15 million) to the United States, and fifteen million dollars (\$15 million) to the State of Texas. Each Plaintiff shall have exclusive control of the civil penalties paid to it.

Out of the payment to the State of Texas:

-- the sum of \$6 million shall be denominated as a penalty within the meaning of § 81.0531 of the Texas Natural Resources Code, and shall be deposited into the Oil-Field Cleanup Fund pursuant to

§91.111(c)(19) of the Texas Natural Resources Code.

-- the sum of \$3 million shall be denominated as a penalty within the meaning of §40.251 of the Texas Natural Resources Code, and shall be deposited into the Coastal Protection Fund pursuant to §40.151 of the Texas Natural Resources Code.

-- the Attorney General of Texas shall recover \$450,000 as reasonable attorneys' fees for work done by the Office of the Attorney General in these cases. These payments are exclusive of any amounts owed by the State of Texas to outside counsel for attorneys' fees and expenses related to this case.

-- outside counsel for the State of Texas may recover reasonable attorneys' fees, investigative costs, and expenses for representation in these cases, subject to approval by the State of Texas.

A) All payments to the United States shall be made by electronic funds transfer (EFT). The EFT will be prepared by the United States Attorney's Office, Financial Litigation Unit (FLU), for the Southern District of Texas. Defendant(s) must contact the FLU within the thirty (30) day payment period to notify the FLU of the date when payment is to be made so that the FLU, in turn, may notify the U.S. Department of Justice, Debt Accounting Operation Group accordingly. The person at the FLU to contact is Debra Gregory (713-567-9543). The FLU will prepare the FEDWIRE Electronic Funds Transfer Form containing the appropriate Bank Code, Bank Name and Account Number and shall send it to the Defendant, by facsimile, to present to Defendant(s) bank.

B) All payments to the State of Texas shall be made by EFT to the Comptroller of Public Accounts, State of Texas, for the Attorney General's Suspense Account, using the following instructions:

Financial Institution: TX COMP AUSTIN

Routing Number: 114900164

Account Name: Comptroller of Public Accounts - Treasury Operations

Account Number to Credit: 463600001

Reference: (to be filled in by Remitter: e.g., Remitter's Name, Case Style, Attorney)

Attention: Chief, Natural Resources Division, Office of the Attorney General (475-4001)

Contact: Abel Rosas (512) 475-4380

Defendants shall send notice to both Federal and State Plaintiffs that such payments have been made, as specified in Section XVI (NOTICES).

8. The United States and the State of Texas shall be deemed judgment creditors for purposes of collection of any penalties under this Consent Decree. Penalty payments made pursuant to this Consent Decree shall not be tax deductible for federal tax purposes. Upon payment in accordance with Paragraph 7 above, the judgment will automatically be released as to the penalties paid.

9. If Defendants fail to timely make any payment as required under this Consent Decree, then, commencing the day after payment is due, Defendants shall be liable for interest on the unpaid balance at the federal judgment interest rate computed in accordance with 28 U.S.C. § 1961, as of the date payment is due, and, if incurred, the costs of enforcement and collection pursuant to the Federal Debt Collection Procedure Act, 28 U.S.C. § 3001 et seq.

VII. OPERATING REQUIREMENTS

10. **General Provisions:** The operating requirements in this Consent Decree apply to all crude oil and/or refined petroleum product pipelines (except the Chase Pipe Line and Minnesota Pipeline) that Defendants own and/or operate (except inactive pipelines), within the territorial jurisdiction of the United States, at the Effective Date of this Consent Decree. Such pipelines owned and/or operated as of the date the Defendants executed this Consent Decree are listed in Appendix B hereto (hereinafter referred to as "Subject Pipelines"). Appendix B shall be updated as appropriate by Defendants within ten (10) days of

the date of entry of this Consent Decree to list such pipelines owned and/or operated by the Defendants as of the Effective Date of this Consent Decree. In the event Defendants place any inactive crude oil or refined petroleum product pipelines that were owned and/or operated by Defendants as of the Effective Date of this Consent Decree into service for the transportation of crude oil and/or refined petroleum products during the duration of this Consent Decree, Defendants shall notify Plaintiffs thirty (30) days prior to such activation, and that pipeline would then be added to the Subject Pipelines, and these operating requirements shall apply to those pipelines as well. In the implementation of the following operating requirements, the Defendants shall adhere to Sound Industry Practice and applicable State law.

11. Initial Assessments: Defendants shall conduct new assessments or complete previous or ongoing assessments (internal and external inspections, tests, and/or surveys) of the Subject Pipelines and shall repair, retool, recondition, and/or replace any pipeline in accordance with Sound Industry Practice. Within ninety (90) days of the entry of this Consent Decree, Defendants shall submit a plan to Plaintiffs that adequately describes the method in which the assessments have or will be made. Plaintiffs reserve the right to review and suggest specific changes to the plan within forty-five (45) days of its receipt. Any such suggested changes from Plaintiffs will be delivered in writing to Defendants by no later than the 45th day following receipt. Within fifteen (15) days after receipt of any such suggestions by Plaintiffs, Defendants will respond to Plaintiffs in writing with any amended plan and a written confirmation that Plaintiffs' suggested changes were adopted, or if any suggested changes were not fully adopted, an explanation of the reasons for not incorporating the changes.

Defendants shall commence any pipeline assessments not already completed in a manner that is consistent with the Defendants' plan as it may have been amended by any suggestions received from

Plaintiffs and incorporated into the plan. Defendants may utilize pertinent data from any prior applicable pipeline risk assessment in completing this requirement. These assessments will be completed within the time constraints set forth in the plan. Any pipeline reconditioning identified as necessary by these initial pipeline assessments in accordance with Sound Industry Practice must be completed within two (2) years from the Effective Date of this Consent Decree.

12. Leak Detection/ Leak Prevention Program: Defendants shall complete the development and implementation of leak detection and leak prevention programs in accordance with Sound Industry Practice and applicable State law. Within ninety (90) days of the entry of this Consent Decree, Defendants shall submit a plan to Plaintiffs adequately describing the leak detection and leak prevention program. Plaintiffs reserve the right to review and suggest specific changes to the plan within forty-five (45) days of its receipt. Any such suggested changes from Plaintiffs will be delivered in writing to Defendants by no later than the 45th day following receipt. Within fifteen (15) days after receipt of any such suggestions by Plaintiffs, Defendants will respond to Plaintiffs in writing with any amended plan and a written confirmation that Plaintiffs' suggested changes were adopted, or if any suggested changes were not fully adopted, an explanation of the reasons for not incorporating the changes. Defendants shall implement the leak detection/leak prevention program in a manner that is consistent with the Defendants' plan as it may have been amended by any suggestions received from Plaintiffs and incorporated into the plan. Defendants shall include the following in the leak prevention and leak detection program:

A) A pipeline testing program aimed at the early detection of internal and external corrosion and other pipeline defects;

B) Analysis of risk assessment criteria to prioritize efforts to prevent pipeline leaks and spills;

C) A system for monitoring and tracking pipeline leaks and spills;

D) A system for managing: (i) abandoned and/or inactive pipelines that are connected to active pipelines on the Effective Date of this Consent Decree; (ii) pipelines that are to be abandoned and/or removed from service; (iii) pipelines returned to service after abandonment or inactivity;

E) A program to analyze the need for, and to provide as necessary, additional protection (including, as appropriate, cover) for exposed pipeline, including exposed pipeline at waterways;

F) A system for determining and recording maximum operating pressure (MOP) on the pipelines and for ensuring that the pipelines are operated in accordance with those MOPs; and

G) A program for insuring that line markers are placed and maintained appropriately for the pipelines.

13. Maintenance and Inspection Program: The Defendants shall complete the development and implementation of a maintenance and inspection program in accordance with applicable law and Sound Industry Practice. Within ninety (90) days of the entry of this Consent Decree, the Defendants shall submit a plan to Plaintiffs adequately describing the maintenance and inspection program to be implemented by Defendants. Plaintiffs reserve the right to review and suggest specific changes to the plan within forty-five (45) days of its receipt. Any such suggested changes from Plaintiffs will be delivered in writing to Defendants by no later than the 45th day following receipt. Within fifteen (15) days after receipt of any such suggestions by Plaintiffs, Defendants will respond to Plaintiffs in writing with any amended plan and a written confirmation that Plaintiffs' suggested changes were adopted, or if any suggested changes were not fully adopted, an explanation of the reasons for not incorporating the changes. Defendants shall implement the maintenance and inspection program in a manner that is consistent with the Defendants' plan

as it may have been amended by any suggestions received from Plaintiffs and incorporated into the plan.

Defendants shall include the following in the maintenance and inspection program:

A) A program aimed at preventing or inhibiting corrosion, including cathodic protection (for example: installation, operation, and maintenance of rectifier units for effective corrosion control on the pipelines);

B) A testing/monitoring program (including smart pigging, where applicable) for early detection of corrosion;

C) A program for performing, as applicable, pipe-to-soil surveys for the pipelines and follow-up maintenance and repair;

D) A program for the installation, operation, and maintenance of pressure monitoring/recording equipment at the pipelines (including pump stations);

E) A program for the performance of periodic visual inspections of pipelines, including the surface conditions on or adjacent to each pipeline right-of-way;

F) A monitoring program (for example, a coupon monitoring program) to monitor the effectiveness of internal corrosion prevention measures; and

G) A program to prepare and maintain mapping documentation of all Subject Pipelines, irrespective of size or diameter of the line, as required by Sound Industry Practice and applicable State law, including submission to appropriate emergency response organizations of copies of such pipeline mapping documentation which includes information regarding shut off or pressure relief valves.

14. **Training Program:** Defendants shall complete the development and implementation of a training program for personnel (including contractors), as appropriate, in corrosion control, leak detection and

prevention, emergency response operations, pipeline systems operation and maintenance, reporting, applicable state regulatory requirements and environmental risk management in accordance with Sound Industry Practice. Within ninety (90) days of the entry of this Consent Decree, Defendants shall submit a plan to Plaintiffs adequately describing the training program. Plaintiffs reserve the right to review and suggest changes to the plan within forty-five (45) days of its receipt. Any such suggested changes from Plaintiffs will be delivered in writing to Defendants by no later than the 45th day following receipt. Within fifteen (15) days after receipt of any such suggestions by Plaintiffs, Defendants will respond to Plaintiffs in writing with any amended plan and a written confirmation that Plaintiffs' suggested changes were adopted, or if any suggested changes were not fully adopted, an explanation of the reasons for not incorporating the changes. Defendants shall implement the training program in a manner that is consistent with the Defendants' plan as it may have been amended by suggestions received from Plaintiffs and incorporated into the plan. The foregoing training shall be conducted by qualified instructors.

15. **Third Party Auditor:** The Defendants' development and implementation of the operating requirements described in this Section shall be audited by an independent third-party auditing firm ("Auditor") retained and compensated by Defendants and approved by Plaintiffs. Within forty-five (45) days of entry of this Consent Decree Defendants shall provide Plaintiffs with the identity and qualifications of the proposed Auditor. Plaintiffs shall not unreasonably withhold approval of any Auditor proposed by Defendants. Plaintiffs shall have thirty (30) days from receipt of Defendants' proposal to approve or disapprove the proposed Auditor. If Plaintiffs disapprove the proposed Auditor, Defendants must propose additional Auditors until Plaintiffs approve the Auditor. If Defendants wish to change Auditors, Defendants shall notify Plaintiffs in writing, provide good cause for the change, and shall propose another Auditor to

Plaintiffs for approval. Any subsequent Auditor must satisfy the requirements of this paragraph.

A) The Auditor's auditing teams shall be comprised of qualified personnel, with scientific or engineering degrees and experience, knowledge and expertise, as appropriate to the aspect being audited, in the operation of oil pipelines, the environmental effects of the operation of oil pipelines and related operations, and the auditing of all such operations, and shall include at least one environmental auditor (qualified within the meaning of ISO 14012).

B) The members of the Auditor's audit teams shall also be cognizant of the laws, regulations, codes, and standards pertaining to the pipelines, as appropriate to the aspect being audited.

C) The Auditor shall have no interests in any of the Defendants' businesses and/or operations and the Auditor and Defendants shall provide Plaintiffs with certified statements of no interest.

D) The Auditor shall annually audit the programs Defendants have implemented to meet the operating requirements of this consent decree, to (1) determine if these programs conform to the requirements specified in this Consent Decree and in the Defendants' plans, and (2) identify any deviations from Sound Industry Practice and applicable law. The Auditor shall conduct an independent review of the programs. Defendants shall provide the Auditor with any information requested, as appropriate to the aspect being audited, and shall provide access to any of its operations to the Auditor for purposes of the audits. The Auditor shall provide program status reports to Plaintiffs as described in the reporting section below (Section IX).

16. Transfer of pipeline: Defendants shall not sell, lease, or otherwise transfer any interest in any of the Subject Pipelines without making available to the party(ies) involved in the subject transaction all material operations and maintenance records, in Defendants' possession or control, regarding the condition

of the pipeline, as determined by inspection, testing, visual observation, or other assessment. Defendants shall notify Plaintiffs at least thirty (30) days prior to any transfer of interest of the identity, business address, phone number, and state of incorporation of the transferee.

VIII. ENVIRONMENTAL PROJECTS

17. Defendants shall perform the following environmental projects:

A) Pipeline Safety Education Project

Defendants shall spend no less than \$1.0 million on a pipeline safety education project, regarding pipelines in the states of Texas, Oklahoma and Kansas, designed to educate the public and the regulated community about improvements to pipeline operation and maintenance which will reduce or eliminate spills. To design and implement this project Defendants will provide funding to a university or other educational institution, subject to the approval of Plaintiffs, with expertise in pipeline design and safety to design a curriculum drawing upon: existing studies in the field, including those addressing major weaknesses in pipelines, including corrosion, third-party damage, operator error, and design defects; available data on size, age, type of product, etc., for crude oil and refined petroleum product lines; reported data on spills; and other appropriate information.

From these data sets the institution shall develop recommendations on:

- (a) accident prevention improvements;
- (b) steps for the prevention of spills; and
- (c) possible remediation approaches.

As part of this project Defendants shall require the educational institution to work with appropriate public and private entities, including Defendants, in developing the curriculum design (which shall be

submitted to Plaintiffs for approval) and distributing the findings to the public and to the regulated community in order to foster improvement in pipeline safety. Within six (6) months of the Effective Date of this Consent Decree, Defendants shall submit a plan for this project to EPA for approval. Defendants shall ensure that this project is completed in accordance with the plan approved by EPA. Such approval shall not be unreasonably withheld. In the event Defendants fail to expend the \$1.0 million for this project as specified herein, Defendants shall pay any portion of the \$1.0 million not so expended to the United States as an additional civil penalty to be paid in the manner provided in Section VI (Payment of Civil Penalties).

B) Acquisition of Property Project

At the time of entry of this Consent Decree, Defendants shall place in an interest bearing escrow account (the "Escrow Account"), \$1.5 million, to be used, along with accrued interest, solely for acquisition, enhancement, and maintenance of wetlands, aquatic property, semi-aquatic property, or prairie containing waterways, appropriate for preservation as wetlands or wildlife habitat, in Oklahoma and Kansas. The acquired property shall be used for the purpose of creating new environments, enhancing existing environments, or protecting, restoring, and improving wildlife habitat and water quality.

Within six (6) months of the entry of this Consent Decree, Defendants shall provide EPA with a proposal for the expenditures set forth above proposing acquisition of at least two parcels of property which are available for acquisition and which meet the requirements of this Paragraph, and describing the acquisition, enhancement, and maintenance proposed. At least one parcel will be in Kansas, and at least one parcel will be in Oklahoma. The acquisition, enhancement, and maintenance proposal, including proposed project manager(s), must be reviewed and approved by EPA prior to its implementation. Such

approval shall not be unreasonably withheld. Defendants shall use their best efforts to accomplish the approved acquisitions within three (3) months of Defendants' receipt of EPA's approval and in no event later than six (6) months after approval.

Any property that is purchased with funds from the Escrow Account shall be held by the purchaser and future owners consistent with the purposes of this Paragraph and shall be maintained in perpetuity as wetlands or wildlife habitat. Defendants shall put in place, or require the acquiring entity to put in place, a permanent conservation easement on the acquired property consistent with applicable state law. In the event Defendants fail to expend the \$1.5 million for this project as specified herein, Defendants shall pay any portion of the \$1.5 million not so expended to the United States as an additional civil penalty to be paid in the manner provided in Section VI (Payment of Civil Penalties).

C) State of Texas Environmental Projects

Defendants shall spend no less than \$2.5 million to conduct projects in the State of Texas shown on Appendix C. The projects will be conducted in the Counties shown, for the purposes that are shown, and subject to the limitations that are shown on Appendix C. Defendants shall provide payment to the entities designated and in the amounts designated on Appendix C within thirty (30) days from the date of entry of this Consent Decree. Defendants shall obtain from the Texas Natural Resources Conservation Commission ("TNRCC") instructions regarding payment, and shall notify the TNRCC concurrent with making each payment. Notices shall be made by regular mail or telecopy to: Scottie Aplin, TNRCC Legal Division, P.O. Box 13087(MC-175), Austin, Texas, 78711-3087, Fax # 512-239-3434. In the event Defendants fail to expend the \$2.5 million for these projects as specified herein, Defendants shall pay any portion of the \$2.5 million not so expended to the State of Texas as an additional civil penalty to be paid

in the manner provided in Section VI (Payment of Civil Penalties).

IX. REPORTING REQUIREMENTS

18. Beginning on the date of entry of this Consent Decree and until termination of this Consent Decree, Defendants shall submit semi-annual status reports to Plaintiffs and the Auditor setting forth all actions taken to comply with the provisions of this Consent Decree, the dates of such actions, and any failure to meet the requirements of the Consent Decree. The first such report will be due six months following the Effective Date of the Consent Decree with subsequent reports due at six-month intervals thereafter. If requested by Plaintiffs or the Auditor, Defendants shall meet with Plaintiffs and/or the Auditor to discuss the Defendants' compliance with the terms of this Consent Decree.

A.) Defendants shall attach to each semi-annual status report an itemized list of:

- 1) All technical reports generated by Defendants or their contractors or agents pursuant to this Consent Decree; and,
- 2) All surveys, test results, inspection reports, incident reports, and repair reports generated by Defendants or their contractors or agents pursuant to this Consent Decree.

Defendants shall provide Plaintiffs or the Auditor with copies of any of the documents on the itemized list or any related data and information upon request.

B.) The Auditor shall submit annual reports to Plaintiffs within sixty (60) days of the end of each successive twelve-month period following the Effective Date of this Consent Decree, providing the Auditor's analysis and conclusions for that period. Each such report shall include a section for each Consent Decree requirement, a description of the Defendants' activities to meet the Consent Decree requirements, a determination of whether the Defendants' programs conform to the requirements specified

in this Consent Decree and in the Defendants' plans, and an assessment of each program's performance, including assessments of any deviations from Sound Industry Practice and applicable law. The reports shall also identify the specific information relied upon for the analysis and conclusions.

19. All submissions by Defendants to Plaintiffs regarding the Defendants' compliance with the terms of this Consent Decree shall be accompanied by a cover letter signed by a Responsible Official of Defendants which attests to the accuracy of the submission. Each submission must also be accompanied by the following certification signed by a Responsible Official of Defendants:

I certify that the information contained in or accompanying this submission is true, accurate and complete. As to those identified portions of this submission for which I cannot personally verify the truth and accuracy, I certify as the company official having supervisory responsibility for the person(s) who, acting upon my direct instructions, made the verification, that this information is true, accurate, and complete.

X. RECORDS RETENTION

20. For one year after the termination of this Consent Decree, Defendants shall preserve and retain all material records, documents, and information currently in their possession or control or which come into their possession or control and which relate in any manner to the performance of the operating requirements under this Consent Decree, regardless of any corporate retention policy to the contrary. Defendants may at their election keep such documents on computer disks, microfiche, or such other media as they deem appropriate.

XI. ACCESS

21. Upon entry of this Consent Decree, Defendants agree to provide the United States and the State of Texas, and the Auditor, including contractors, and other authorized persons performing actions at the direction of the United States, State of Texas or the Auditor, prompt access, at all reasonable times to all

property on which the subject pipelines and other related facilities are located for:

A) Verifying compliance with the terms of this Consent Decree;

B) Verifying any data or information submitted by Defendants pursuant to this Consent Decree;

and,

C) Performing or observing the activities of the Auditor under this Consent Decree.

22. Notwithstanding any provisions of this Consent Decree, the United States and the State of Texas retain all rights of access, information gathering, and response authorities, under the CWA, OPA, the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C.

§ 9601 et. seq., the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et. seq., State law, and any other applicable statutes or regulations.

23. Defendants shall provide the United States and the State of Texas, upon request, copies of all material records, documents and information currently within or which come into their possession or control and which relate to factual information regarding the implementation of this Consent Decree, including without limitation, reports, correspondence, or other documents or information related to the work performed pursuant to this Consent Decree.

24. No provision of this Consent Decree shall be interpreted as a waiver of any privilege, including, but not limited to the attorney-client communications privilege or the work product exemption, or as a waiver of any proprietary interest in confidential business information. Additionally, nothing herein shall be construed to require Defendants to submit privileged or confidential business information to Plaintiffs. Defendants shall not attempt, however, to assert any such claims regarding plans, notices, correspondence or reports required to be submitted to Plaintiffs under this Consent Decree. This shall not affect any rights

Defendants may have to claim business confidentiality or privilege regarding other records or information that may be requested by Plaintiffs under this Consent Decree or otherwise.

XII. STIPULATED PENALTIES

25. Defendants shall be liable to Plaintiffs for stipulated penalties in the amounts set forth in this Section for failure to comply with their enumerated obligations under this Consent Decree unless excused under the FORCE MAJEURE Section.

26. The stipulated penalties are as follows:

<u>Period of Noncompliance</u>	<u>Penalty for Noncompliance</u>
1st through 15th day	\$1,000 per violation, per day or portion thereof
16th through 30th day	\$1,750 per violation, per day or portion thereof
31st day and beyond	\$2,500 per violation, per day or portion thereof

27. Any stipulated penalties paid by Defendants shall be paid 50% to the United States and 50% to the State of Texas in accordance with the payment instructions in Section VI above.

28. Stipulated penalties shall automatically begin to accrue on the first day Defendants fail to satisfy any obligation or requirement of this Consent Decree and shall continue to accrue through the final day of correction of the noncompliance or completion of the activity, except that: (1) for stipulated penalties related to any failure to use Sound Industry Practice, the stipulated penalties shall automatically begin to accrue on the first day Defendants are aware or, through the exercise of reasonable diligence, should have been aware, of a failure to satisfy the obligation or requirement; and, (2) with respect to judicial review by this Court of any dispute under Section XIII (Dispute Resolution), stipulated penalties shall not accrue during the period, if any, beginning on the 31st day after the Court's receipt of the final submission regarding such dispute until the date that the Court issues a final decision regarding such dispute. Nothing herein shall

prevent the simultaneous accrual of separate penalties for separate violations of this Consent Decree. In the event Plaintiffs determine that Defendants are out of compliance with any terms of this Consent Decree, Plaintiffs shall expeditiously notify Defendants of that determination.

29. Stipulated penalties shall be payable by Defendants upon written demand by Plaintiffs identifying the violations. Defendants shall, within thirty (30) days of receipt of such demand, either pay the amount demanded or notify Plaintiffs in writing of each violation they deny and the basis for that denial. If Defendants invoke dispute resolution and the Plaintiffs' position is upheld, then Defendants shall pay all accrued penalties, including those accruing during dispute resolution, within fifteen (15) days of the resolution of the dispute.

30. Payments made under this Section shall be in addition to any other remedies or sanctions available to Plaintiffs, by virtue of the Defendants' failure to comply with the requirements of this Consent Decree or any applicable statutes or regulations.

XIII. DISPUTE RESOLUTION

31. The dispute resolution procedures in this Section shall be the exclusive mechanism for resolving disputes arising under, or with respect to, this Consent Decree. However, the procedures set forth in this Section shall not apply to action by the Plaintiffs to enforce obligations of the Defendants where the Defendants have not timely disputed in accordance with this Section or other provision of the Consent Decree.

32. Any dispute which arises under or with respect to this Consent Decree shall in the first instance be the subject of informal negotiations between or among the parties to the Dispute. The period for informal negotiations shall be twenty-one (21) days from the time the dispute arises, unless this period is

extended by written agreement of the parties to the dispute. The dispute shall be considered to have arisen when one party sends the other parties a written Notice of Dispute after notifying the other party by telephone.

33. In the event that the parties cannot resolve a dispute by informal negotiations under the preceding Paragraph, then the parties to the dispute shall submit the dispute to non-binding mediation which shall be completed within twenty-one (21) days. The selection of an appropriate impartial mediator shall be agreed to by the parties or if the parties cannot agree shall be determined by the Court. In the event that the parties cannot resolve a dispute by informal negotiations under the preceding Paragraph or by mediation under this Paragraph, then the position advanced by the Plaintiffs shall be considered binding unless, within ten (10) working days after the conclusion of the informal negotiation period and any mediation, Defendants petition the Court to resolve the dispute. This ten-day period may be extended by written agreement of the parties to the dispute. Nothing herein shall be construed to allocate the burden of proof to be imposed by the Court in any dispute resolution proceeding under this Consent Decree.

34. Actions to involve the Court in the resolution procedures under this Section shall not extend, postpone, or affect in any way any obligations of Defendants under this Consent Decree that are not directly in dispute, unless the Parties by mutual consent or the Court determines otherwise. Stipulated penalties with respect to the disputed matter(s) shall continue to accrue, in the manner provided for in Section XII, but payment shall be stayed pending resolution of a dispute over a request for stipulated penalties made in accordance with Section XII.

XIV. FORCE MAJEURE

35. The Defendants' obligation to comply with the requirements of this Decree shall only be deferred

to the extent and for the duration that the delay is caused by a "Force Majeure Event."

A "Force Majeure Event" is defined as a delay or violation that has been or will be caused by circumstances beyond the control of Defendants or an entity controlled by Defendants and that could not have been foreseen and prevented by the exercise of due diligence.

36. If any Force Majeure Event occurs which causes or may cause Defendants to be in violation of any provision of this Decree, Defendants shall notify Plaintiffs in writing within ten (10) days of the time Defendants have notice of the event. The notice shall specifically reference this Section of the Decree and describe in detail the anticipated length of time the violation may persist, the precise cause or causes of the violations, the measures taken or to be taken by Defendants to prevent or minimize the violations and to prevent future violations, and the schedule by which those measures will be implemented. Defendants shall adopt reasonable measures necessary to avoid or minimize any such violation. Failure by Defendants to comply with the notice requirements of this Section shall constitute a waiver of the Defendants' right to obtain an extension of time for their obligations under this Section of the Decree based on such event.

A) If Defendants assert in their notice, and Plaintiffs agree, that the violation has been or will be caused by a Force Majeure Event, the time for performance of such requirement will be extended for a period not to exceed the actual delay resulting from such event, and stipulated penalties shall not be due for said delay.

B) Plaintiffs shall notify Defendants in writing of their agreement or disagreement with Defendants' claim of a Force Majeure Event within ten (10) days of receipt of the Defendants' notice under this Section.

C) If Plaintiffs disagree, Defendants may submit the matter for resolution pursuant to Section XIII of this Decree (Dispute Resolution). If Defendants submit the matter to the Court for resolution and the

Court determines that the violation was caused by a Force Majeure Event, Defendants shall be excused from that violation (including the stipulated penalties for that violation) but only for the period of time the violation continues due to the circumstances that caused the Force Majeure Event.

D) Compliance with any requirement of this Decree by itself shall not constitute compliance with any other requirement. An extension of one compliance date based on a particular incident does not result in an automatic extension of other subsequent compliance date or dates. Defendants must make an individual showing of proof regarding each requirement for which an extension is sought.

E) Defendants shall bear the burden of raising and proving that any delay or violation of any requirement of this Decree was caused by a Force Majeure Event. Defendants shall also bear the burden of proving the duration and extent of any delay or violation found attributable to the circumstances that caused a Force Majeure event.

XV. EFFECT OF SETTLEMENT

37. In consideration of payment of civil penalties and performance of the operating requirements and projects required herein, Plaintiffs release all civil claims against and covenant not to sue or to take administrative action against Defendants and each of their affiliated assigns, affiliated successors, directors, officers, and employees, for injunctive relief and civil penalties arising from the discharges referenced in (1) the complaints and amended complaints in this action and Civil Action No. 97-CV687B(W) in the Northern District of Oklahoma and (2) in Appendix A hereto. This release and covenant does not include claims for: cleanups regarding the settled discharges, reimbursement of any disbursements from the federal Oil Spill Liability Trust Fund, and natural resource damages. This release and covenant not to sue extends only to the Defendants and each of their affiliated assigns, affiliated successors, directors, officers, and

employees, and does not extend to any other person. This release and covenant regarding civil penalties is effective upon the payment of the penalty as provided in Section VI (Payment of Civil Penalties), and as to injunctive relief is effective upon compliance with the requirements of Section VII (Operating Conditions) and Section VIII (Environmental Projects) of this Consent Decree.

38. In any subsequent administrative or judicial proceedings initiated by Plaintiffs for matters other than those released in Paragraph 37 neither Plaintiffs nor Defendants shall assert, and may not maintain, any defense or claim of waiver, res judicata, collateral estoppel, issue preclusion, or claim-splitting based upon any contention that the claim or issue was decided through any Party's agreement to, or the entry of, this Consent Decree.

39. Defendants hereby covenant not to sue, and agree not to assert any claims or causes of action, against the United States or any State of Texas government entity under the CWA, OPA, or any other federal or State law or regulation with respect to the discharges covered by Paragraph 37 including without limitation, any direct or indirect claim for reimbursement under any provision of law or for events arising out of removal activities in connection with the discharges.

XVI. NOTICES

40. Whenever, under the terms of this Consent Decree, written notice is required to be given or a report or other document is required to be sent by one party to another, it shall be directed to the individuals at the addresses specified below, unless those individuals or their successors give written notice of a change. All notices and submissions shall be considered effective upon receipt, unless otherwise provided.

As to the United States:

To EPA:

Director, Superfund Division, Mail Code 6-SF
United States Environmental Protection Agency
Region VI
1445 Ross Avenue, Dallas, Texas 75202

and

To the United States Department of Justice:

Chief,
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
Washington, D.C. 20044
DOJ Reference # 90-5-1-1-4109

As to State of Texas:

To the Office of the Attorney General:

Office of the Attorney General, State of Texas
Attn: Chief, Natural Resources Division (MC-015)
P.O. Box 12548
Austin, TX 78711-2548

Notices to the Office of the Attorney General should reference this case and "AG#97-657333".

and

To the Railroad Commission:

Railroad Commission of Texas
Attn: Lindil Fowler, General Counsel
P.O. Box 12967
Austin, Texas 78711-2967

As to Defendants:

General Counsel
Koch Industries, Inc.
41111 East 37th Street North
Wichita, Kansas 67220

XVII. RETENTION OF JURISDICTION

41. This Consent Decree shall be considered an enforceable judgment for purposes of post-judgment collection in accordance with the provisions of the Consent Decree, Rule 69 of the Federal Rules of Civil Procedure and other applicable federal statutory authority.

42. This Court retains jurisdiction over both the subject matter of this Consent Decree and the Parties for the duration of the performance of the terms and provisions of this Consent Decree for the purpose of enabling any of the Parties to apply to this Court at any time for such further order, direction, and relief as may be necessary or appropriate for the construction or modification of this Consent Decree, or to effectuate or enforce compliance with its terms, or to resolve disputes in accordance with Section XIII (DISPUTE RESOLUTION).

XVIII. MODIFICATION

43. Material modifications to this Consent Decree may be made only as approved by the Court. Modifications that do not materially alter the Defendants' obligations under this Consent Decree may be made without consent of the Court by written agreement of the Parties.

XIX. LODGING AND PUBLIC COMMENT PERIOD

44. This Consent Decree shall be lodged with the Court for a period of at least thirty (30) days for public notice and comment in accordance with 28 C.F.R. § 50.7. Plaintiffs reserve the right to withdraw

or withhold consent to the Consent Decree if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate. Defendants agree not to oppose entry of this Consent Decree.

45. If for any reason the Court should decline to approve this Consent Decree in the form presented, the agreement is voidable at the sole discretion of any Party and the terms of the agreement may not be used as evidence in any litigation between the Parties.

XX. EFFECTIVE DATE

46. The Effective Date of this Consent Decree is that date upon which it is entered by the Court.

XXI. TERMINATION

47. This Consent Decree shall be subject to termination upon motion by any party after Defendants have satisfied the requirements set forth herein for the time periods specified herein. At such time as Defendants believe that they have fulfilled these requirements, Defendants shall so certify to Plaintiffs. Not earlier than thirty (30) days after such certification, any party may apply to the Court for termination of the Consent Decree. This shall not terminate those provisions which by their terms have continuing effect.

XXII. DOCUMENTATION

48. The Parties agree that this Consent Decree constitutes a single, integrated written agreement expressing their entire agreement. Any prior statements, representations, or promises, written or oral, regarding the subject matter of this Consent Decree, have been, and are, superceded by this Consent Decree.

49. The captions contained in this Consent Decree have been inserted for the purposes of convenience and reference only and shall not affect the construction of this Consent Decree or any of its provisions.

50. This Consent Decree may be executed in any number of counterparts, and each original executed counterpart shall have the same force and effect as the original instrument.

XXIII. SIGNATORIES

51. The undersigned representatives of Defendants, the State of Texas, and the United States certify that they are fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind such party to this document.


SO ORDERED THIS 14th DAY OF March 1999.


United States District Judge

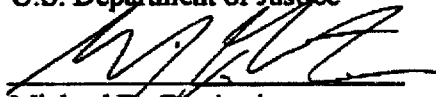
THE UNDERSIGNED enter into this Consent Decree in the matter of United States et al. v. Koch Industries Inc., et al., H 95-1118 (Houston, Texas) and 97-CV687B(W) (Tulsa, Oklahoma).

FOR THE UNITED STATES OF AMERICA:

Date: 1/12/00


Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources Division
U.S. Department of Justice

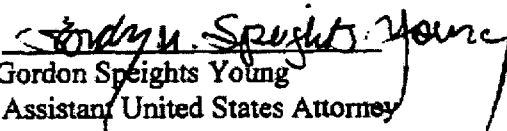
Date: 1/12/00


Michael D. Goodstein
Senior Attorney
Patrick M. Casey
Trial Attorney
Environmental Enforcement Section
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044
(202) 514-1111

P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044
(202) 514-1111

Mervyn M. Mosbacher
United States Attorney
Southern District of Texas


Date: 1-12-2000

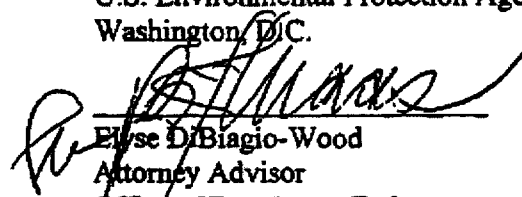

Gordon Speights Young
Assistant United States Attorney
S.D. Texas
P.O. Box 61129
Houston, Texas 77208-1129
(713) 567-9501

Stephen C. Lewis
United States Attorney
Northern District of Oklahoma

Phil Pinnell
Assistant U.S. Attorney
Northern District of Oklahoma
3900 U.S. Courthouse
333 W. 4th Street
Tulsa, Oklahoma 74103
(918) 581-7670

Date: 1/11/00


Steven A. Herman
Assistant Administrator for
Enforcement
U.S. Environmental Protection Agency
Washington, D.C.


Elise DiBiagio-Wood
Attorney Advisor
Office of Regulatory Enforcement
Water Division
U.S. Environmental Protection Agency
Washington, D.C.

Date:

1/11/00


Gregg A. Cooke

Regional Administrator

U.S. Environmental Protection Agency

Region 6

1445 Ross Avenue

Dallas, Texas 75202-2733

Date:

1/11/00


Gary Smith

Senior Assistant Regional Counsel

Suzanne Smith-Roquemore

Assistant Regional Counsel

Office of Regional Counsel

U.S. Environmental Protection Agency

Region 6

1445 Ross Avenue

Dallas, Texas 75202-2733

THE UNDERSIGNED enter into this Consent Decree in the matter of
United States et al. v. Koch Industries Inc., et al., H 95-1118 (Houston, Texas) and 97-
CV687B(W) (Tulsa, Oklahoma).

Date: January 11, 2000

William Lee
for

Dennis Grams, P.E.
Regional Administrator, Region VII
U.S. Environmental Protection Agency
901 N. 5th Street
Kansas City, Kansas 66101
(913)551-7006
(913)551-7925 fax

Date: 11 January 2000

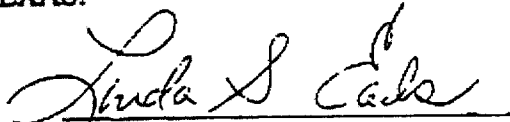
Julie M. Van Horn

Julie M. Van Horn
Senior Assistant Regional Counsel
U.S. Environmental Protection Agency
901 N. 5th Street
Kansas City, Kansas 66101
(913)551-7889
(913)551-7925 fax

THE UNDERSIGNED enter into this Consent Decree in the matter of United States et al. v. Koch Industries Inc., et al., H 95-1118 (Houston, Texas) and 97-CV687B(W) (Tulsa, Oklahoma).

FOR THE STATE OF TEXAS:

Date: 1/11/00



Linda S. Eads
Deputy Attorney General for Litigation
Texas Attorney General's Office
P.O. Box 12548
Austin, Texas 78711
(512) 463-2191

Date: _____

Thomas Edwards
Assistant Attorney General
Natural Resources Division
300 W. 15th Street
Austin, Texas 78701
(512) 475-4003

Date: _____

W. Wade Porter
Jeff Civins
Haynes and Boone, LLP
600 Congress Avenue, Suite 1600
Austin, Texas 78701
(512) 867-8400

Date: _____

Harrison Vickers
III Allen Center
The Vickers Law Firm
333 Clay, 49th Floor
Houston, Texas 77002
(713) 739-8989

THE UNDERSIGNED enter into this Consent Decree in the matter of United States et al. v. Koch Industries Inc., et al., H 95-1118 (Houston, Texas) and 97-CV687B(W) (Tulsa, Oklahoma).

FOR THE STATE OF TEXAS:

Date: _____

Linda S. Eads
Deputy Attorney General for Litigation
Texas Attorney General's Office
P.O. Box 12548
Austin, Texas 78711
(512) 463-2191

Date: 1/11/2000

Thomas Edwards
Assistant Attorney General
Natural Resources Division
300 W. 15th Street
Austin, Texas 78701
(512) 475-4003

Date: 1/11/00

W. Wade Porter
Jeff Civins
Haynes and Boone, LLP
600 Congress Avenue, Suite 1600
Austin, Texas 78701
(512) 867-8400

Date: 1/10/2000

Harrison Vickers
Harrison Vickers
III Allen Center
The Vickers Law Firm
333 Clay, 49th Floor
Houston, Texas 77002
(713) 739-8989

THE UNDERSIGNED enter into this Consent Decree in the matter of
United States et al. v. Koch Industries, Inc., et al., H95-1118 (Houston, Texas) and
97-CV687B(W) (Tulsa, Oklahoma).

FOR DEFENDANT KOCH INDUSTRIES, INC.:

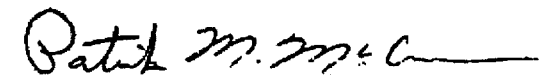
Date: 1-10-00



B. R. Caffey
Executive Vice President - Operations
Koch Industries, Inc.
4111 E. 37th Street North
Wichita, Kansas 67220

FOR DEFENDANT KOCH GATHERING SYSTEMS
(A Division of Koch Pipeline Company, L.P.):

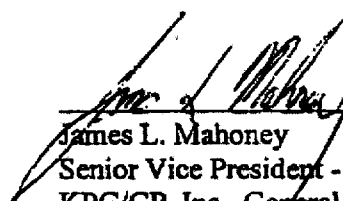
Date: 1/7/2000



Patrick McCann
Senior Vice President
Koch Pipeline Company, L.P.
4111 E. 37th Street North
Wichita, Kansas 67220

FOR DEFENDANT KOCH PETROLEUM GROUP, L.P.,
for itself and as successor in interest to
CITRONELLE PIPELINE CO. and KOCH OIL COMPANY
By KPG/GP, Inc., General Partner,
(formerly Koch Refining Company, L.P.):

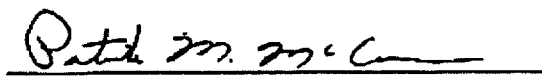
Date: 1-11-00



James L. Mahoney
Senior Vice President - Operations
KPG/GP, Inc., General Partner
Koch Petroleum Group, L.P.
4111 E. 37th Street North
Wichita, Kansas 67220

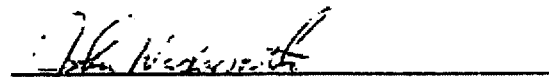
FOR DEFENDANT KOCH SERVICE COMPANY
(A Division of Koch Pipeline Company, L.P.):

Date: 1/7/2000


Patrick McCann
Vice President
Koch Service Company
4111 E. 37th Street North
Wichita, Kansas 67220

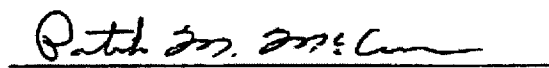
FOR DEFENDANT KOCH MATERIALS COMPANY

Date: 1/7/00


John Wadsworth
Vice President
Koch Materials Company
4111 E. 37th Street North
Wichita, Kansas 67220

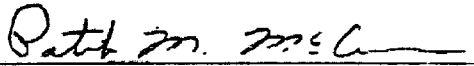
FOR DEFENDANT CHASE PIPE LINE COMPANY:

Date: 1/7/2000


Patrick McCann
Vice President
Chase Pipe Line Company
4111 E. 37th Street North
Wichita, Kansas 67220


FOR DEFENDANT BOW PIPE LINE COMPANY
(A Division of Koch Pipeline Company, L.P.):

Date: 1/7/2000


Patrick McCann
Senior Vice President
Koch Pipeline Company, L.P.
4111 E. 37th Street North
Wichita, Kansas 67220

FOR DEFENDANT KOCH PIPELINE COMPANY, L.P.

Date: 1/7/2000


Patrick McCann
Senior Vice President
Koch Pipeline Company, L.P.
4111 E. 37th Street North
Wichita, Kansas 67220

APPENDIX A

USA v. Kil, et al.
 U.S.D.C. for the Southern District of Texas, Houston Div.,
 Case No. H 95 1118
 U.S.D.C. for the Northern District of Oklahoma,
 Case No. 97 CV 687BW
 Additional Discharges

DATE	LOCATION	FACILITY	NRC NUMBER	AMOUNT SPILLED (BBLs)	CAUSE
5/1/99	Des Moines, IA	Wood River P/L	482256	3608	3rd Party
1/8/99	Duval Co., TX	Benevides Station	470025	10500	Corrosion
11/25/98	Gonzales Co., TX	Rosanky-Nixon P/L	465412	199	Corrosion
10/30/98	Duval Co., TX	Duval Station	N/A	405	Corrosion
10/19/98	Karnes Co., TX	Falls City	460379	783	Tank Failure/Contain- ment Failure
10/18/98	Dewey Co., OK	Harmon 4"	460364	800	Corrosion
5/10/98	Dane Co., WI	Wisconsin P/L - Madison Terminal	436200	60	Failed Valve
12/26/97	Karnes Co., TX	Falls City 4"	N/A	475	Corrosion
9/11/97	Pottawatomie Co., OK	Tribbey-Maud	403165	30	3rd Party
6/23/97	Payne Co., OK	Cherokee-Texaco Delivery	392458	100	Overpressurization
5/7/97	Lincoln Co., OK	McCarney 10"	386427	100	Operator Error

Appendix B
Subject Pipelines

Wisconsin Pipeline (Refined Products)		
Line	Size	Mileage
Pine Bend-Eau Claire	12.75	83.08
Eau Claire-Junction City	12.75	86.72
Junction City-Wild Rose	10.75	44.23
Wild Rose-Waupun	10.75	46.53
Waupun-Granville	10.75	52.38
Waupun-Madison	8.6	65.83
Total:		378.77

Wood River		
Line	Size	Mileage
Hartford-Paris	20	122.31
Paris-Jacksonville	20	18.75
Jacksonville-Bethany	20	108.62
Bethany-Des Moines	24	88.17
Des Moines-Mason City	24	105.1
Mason City-Clear Lake	18	7.88
Clear Lake-Pine Bend	18	115.17
Total:		566

Minnesota		
Line	Size	Mileage
Minnesota Jet Pine Bend-Airport	10.75	12.91
Total:		12.91

Texas Pipeline I (Refined Products)		
Line	Size	Mileage
Corpus Christi-Beeville	16	60.24
Beeville-San Antonio	16	74.25
San Antonio-Austin	16	95.25
Austin-Waco	16	108.69
Total:		338.43

Texas Pipeline II (Refined Products)		
Line	Size	Mileage
Corpus Christi-Gonzales	18	136.46
Gonzales-Waco	18	147.62
Waco-Hillsboro	14, 16	109.28
Hillsboro-Fort Worth	14	52.66
Total:		446.02

Southwest Pipeline		
Line	Size	Mileage
Bell	4	12.7274
Falls	4	26.0713
Total:		38.7987

South Texas Crude Oil System			
Line	Segment	Size	Mileage
South Main Line Benavides to Viola	Agua Dulce to Viola - #1	8"	24.91
South Main Line Benavides to Viola	Agua Dulce to Leopard - #2	8"	23.55
Viola to KRC East - 10"	Viola to KRC East - 10"	10.75	6.74
South Line Benavides to Viola Line	Seeligson to Agua Dulce	10"	30.76
North Line	Mayo Jct to E White Pt	10"	5.19
North Main Line RLC 12"	East White Point to North Meter Bank	12"	4.37
North Line Ingleside to Viola 16"	Ingleside to Viola 16" (Foreign Crude)	16	25.49
North Main Line 12"	New Quintana to Refugio	12"	11.19
North Main Line RLC 12"	Refugio to Ingleside Jct	12"	28.10
North Line	Ingleside Jct to Mayo Jct	10"	12.00
North Line Pearsall to Mayo Jct.	Pearsall to Dilley	10"	14.31
North Line Pearsall to Mayo Jct.	Dilley to Three Rivers	10"	62.43
North Line Pearsall to Mayo Jct.	Three Rivers to Mayo Jct.	10"	62.30
Viola to KRC East	Viola to Viola	8"	0.20
South Main Line	Benavides to Agua Dulce #1	8"	32.43
Sun Field to Seeligson 6"/8"	Kelsey to Seeligson Station - 8"	8.625	51.88
Sun Field to Seeligson 6"/8"	Sun Field to Kelsey	6"	10.62
South Main Line	Government Wells to Benavides	8"	22.00
Mirando to Government Wells Three Way	Mirando to Three Way Trap	8"	14.00
South Main Line	DaVal to Three-Way	8"	3.90

South Main Line	Three Way to Govt. Wells 6"	6.625	1.90
North Main Line	Petrus to Refugio 8"	8.625	39.10
North Main Line	Placedo to Tivoli 6"	6.625	16.80
North Main Line	Tivoli to 12" RLC Tie-in 6"	6.625	32.60
Caldwell Main Line	Nixon to Petrus 8"	8.625	45.80
Caldwell Main Line	Hearne to Shaft 6"	6.625	21.34
Caldwell Main Line	Shaft to Gerdes 6"	6.625	23.05
Caldwell Main Line	Gerdes to Three Way 6"	6.625	32.30
Caldwell Main Line	Three Way to Rosanky 8"	8.625	12.37
Caldwell Main Line	Rosanky to Nixon 8"	8.625	55.80
Caldwell Main Line	Caldwell 6"	6.625	4.00
Caldwell Main Line	West Point to Three Way 6"	6.625	3.00
Total:			754.43

Line	Segment	Size	Mileage
Caso Cargo	Koch East Refinery to Koch West Refinery	14"	7.9

Line	Segment	Size	Mileage
Star	San Antonio Term'l to Motiva Terminal	8.0	3.2

Line	Segment	Size	Mileage
Southlake	Eules to Southlake Delivery Station	12.0	12.0

Line	Segment	Size	Mileage
DFW 8"	Eules to Ogden Term'l	8.0	8.31

**APPENDIX C
SUPPLEMENTAL ENVIRONMENTAL PROJECTS
STATE OF TEXAS**

PROJECT 1

ORGANIZATION: The Coastal Bend Bays & Estuaries Program

MISSION: A nonprofit organization established to protect and improve the quality of the Coastal Bend Bays and Estuary system; encompassing the twelve counties of the Coastal Bend Council of Governments, extending from the land-cut in Baffin Bay, through the Corpus Christi Bay system, and north to the Aransas National Wildlife Refuge.

PROJECT: Provide assistance to the implementation of the estuary program. Assistance will be limited to the implementation of specific environmental preservation/conservation projects, as approved by the Texas Natural Resource Conservation Commission (TNRCC). These projects must directly benefit the environment in the jurisdiction of the Coastal Bend Bays & Estuaries Program with a preference for projects in San Patricio County. Defendants shall require, as a condition of the grant, that this project be completed within eighteen (18) months from the Effective Date of this Consent Decree.

BENEFITS: Protect and restore the health and productivity of the bays and estuaries.

COST: Defendants will contribute \$1,500,000 to the Coastal Bend Bays & Estuaries Program.

PROJECT 2

ORGANIZATION: Resource Conservation and Development, Inc.

MISSION: A nonprofit organization founded for the purpose of accelerating the conservation, development and utilization of natural resources, to improve the general level of economic activity, and to enhance the environment and standard of living of citizens in authorized areas.

PROJECT: Provide qualifying rural homeowners and rural schools in Wilson and Gregg counties who have failing wastewater treatment systems with technical and financial assistance to install alternative wastewater treatment systems. Defendants shall require, as a condition of the grant, that this project be completed within three hundred and sixty-five (365) days from the Effective Date of this Consent Decree.

BENEFITS: Protects drinking and recreational water sources from contamination due to failing treatment systems.

COST: Defendants will contribute a total of \$500,000 to Resource Conservation and Development, Inc., for Wilson and Gregg Counties, with half of the contribution to be spent in each county.

PROJECT 3

ORGANIZATION: Corpus Christi Fire Department

MISSION: To protect and serve citizens of Corpus Christi and Nueces County by providing for response to fire and hazardous materials incidents.

PROJECT: Purchase of the "Emergency 1" hazardous material response vehicle, which will contain emergency response equipment, to include air monitoring equipment, personal protective equipment, spill response and containment equipment, and a remote video camera with telescopic mast. The vehicle will act as a command post and communication center for responding to the release of hazardous materials. Defendants shall require, as a condition of the grant, that this purchase be completed within six (6) months from the Effective Date of this Consent Decree.

BENEFITS: Protect the environment and improve public safety by enhancing the ability of the Corpus Christi Fire Department to respond to emergency releases of hazardous materials.

COST: Defendants will contribute \$350,000 to the Corpus Christi Fire Department.

PROJECT 4

ORGANIZATION: Corpus Christi/Nueces County Local Emergency Planning Committee (LEPC)

MISSION: A governmental entity organized for the purpose of disaster preparedness; coordinator of responses to the release of hazardous materials in the Corpus Christi/Nueces County area.

PROJECT: Provide for the purchase of site specific alerting device systems for at-risk areas in and around chemical industries in the Corpus Christi/Nueces County area. Defendants shall require, as a condition of the grant, that this purchase be completed within six (6) months from the Effective Date of this Consent

Decree.

BENEFITS: Protect and improve public safety by enhancing the ability of the LEPC to notify and instruct the public regarding emergencies involving the release of hazardous materials.

COST: Defendants will contribute \$150,000 to the Corpus Christi/Nueces County Local Emergency Planning Committee (LEPC).

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United States District Court
Southern District of Texas
FILED

SEP 28 2000

Michael N. Milby, Clerk of Court

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION

UNITED STATES OF AMERICA

V.

KOCH INDUSTRIES, INC.

KOCH PETROLEUM GROUP, L.P.

DAVID L. LAMP

VINCENT A. MIETLICKI

JOHN C. WADSWORTH

JAMES W. WEATHERS, JR.,

Defendants

CRIMINAL NO. **C-00-325**

18 U.S.C. § 371 (Conspiracy)

42 U.S.C. § 7413(c)(1)
(Failure to Install Emission
Control Equipment to Prevent
Emissions of Hazardous Air
Pollutants as Required by the
Clean Air Act)

42 U.S.C. § 9603(b)
(Failure to Report Releases of
Hazardous Substances)

18 U.S.C. § 1001 (False Statements)

18 U.S.C. § 2 (Aiding and Abetting)

INDICTMENT

THE GRAND JURY CHARGES THAT:

COUNT 1

At all times material to this Indictment,

THE CLEAN AIR ACT

1. The Clean Air Act was enacted by Congress to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare. Title 42, United States Code, Sections 7401, et seq.

2. The Clean Air Act authorizes the United States Environmental Protection Agency

TRUE COPY I CERTIFY
ATTEST: 9-5-81
MICHAEL N. MILBY, Clerk of Court
By Donna Terrell
Deputy Clerk

(EPA) to identify "hazardous air pollutants" and to establish standards to prevent or limit the emission of hazardous air pollutants into the atmosphere. Those standards established by EPA are known as National Emission Standards for Hazardous Air Pollutants (NESHAP).

3. Congress and EPA have established that benzene is a hazardous air pollutant. Title 42, United States Code, Section 7412(b). EPA added benzene to the list of pollutants determined to be hazardous in 1977, based on scientific reports which strongly suggested an increased incidence of leukemia in humans exposed to benzene. 42 Federal Register 29332 (1977).

4. Pursuant to the authority granted to it, the EPA established various standards, including the National Emission Standards for Benzene Waste Operations, (hereinafter referred to as benzene NESHAP), that apply to petroleum refineries. Title 42, United States Code, Section 7412(d).

5. Refineries whose aqueous waste streams contain 10 megagrams (a megagram is a metric ton, equal to approximately 2,200 pounds) or more of benzene on an annual basis are subject to equipment, performance, design and operational standards, to limit emissions of benzene. Title 42, United States Code, Section 7412; Title 40, Code of Federal Regulations, Sections 61.340, et seq. Aqueous waste streams are those containing 10 percent or more water. Title 40, Code of Federal Regulations, Section 61.342(a)(1).

6. The defendant **KOCH PETROLEUM GROUP, L.P.** owned and operated petroleum refineries in Nueces County, Texas, at which **KOCH PETROLEUM GROUP, L.P.** refined petroleum and manufactured chemicals. One refinery was located on Suntide Road (the West Plant). The other refinery was acquired by **KOCH PETROLEUM GROUP, L.P.** during 1995 (the East Plant). The defendants **KOCH INDUSTRIES, INC.**, and **KOCH PETROLEUM GROUP, L.P.** treated both refineries as a single facility for financial

recordkeeping purposes. On and after February 1994, the defendant **KOCH INDUSTRIES, INC.**, through its agents and employees, and together with defendant **KOCH PETROLEUM GROUP, L.P.**, operated the West Plant.

7. Aqueous waste streams at the West Plant contained 10 megagrams or more of benzene on an annual basis and, therefore, the defendants, **KOCH INDUSTRIES, INC.** as the operator of the West Plant, and **KOCH PETROLEUM GROUP, L.P.** as the owner and operator of the West Plant were required to install and operate equipment to prevent benzene emissions into the atmosphere from non-exempt waste streams. The defendants, **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** were required to comply with the "control requirements" of the benzene NESHAP regulations.

8. Refineries whose aqueous waste streams contain more than 10 megagrams of benzene on an annual basis must choose a compliance option. The defendant, **KOCH PETROLEUM GROUP, L.P.**, chose the "6 megagram option," which meant the West Plant was limited to not more than 6 megagrams benzene on an annual basis in waste streams which were not controlled for air emissions (hereinafter "uncontrolled" waste streams). Title 40, Code of Federal Regulations, Section 61.342(e)(2)(i).

9. Refineries subject to the control requirements of the benzene NESHAP must file an annual report that reports, among other things, the refinery's total annual quantity of benzene waste in its "uncontrolled" waste streams. Title 40, Code of Federal Regulations, Section 61.357(a)(2) and (3)(vi).

10. The benzene NESHAP standards provide that any non-exempt waste stream containing benzene subject to the regulations must be managed and treated in waste management

units and by treatment processes that comply with the standards. Title 40, Code of Federal Regulations, Section 61.342(c).

11. A waste management unit means a piece of equipment, structure or transport mechanism used in handling, storage, treatment or disposal of waste. Examples of waste management units are tanks, oil-water separators and individual drain systems. Individual drain systems include process drains, junction boxes and sewer lines. Title 40, Code of Federal Regulations, Section 61.341.

12. Examples of waste streams that may be subject to benzene NESHAP control and treatment requirements are process wastewater (water which comes in contact with benzene during manufacturing or processing operations in a process unit), product tank drawdown (any material or mixture of materials discharged from a product tank in order to remove water or other contaminants from the tank), slop oil (the floating oil and solids which accumulate on the surface of an oil-water separator) and sludge removed from waste management units, and ballast water. Title 40, Code of Federal Regulations, Section 61.341.

13. A tank used to manage or treat non-exempt waste containing benzene subject to the regulations must be equipped either with a floating roof, or a fixed roof and a closed-vent system that routes vapor flow to control devices. Title 40, Code of Federal Regulations, Section 61.343. A floating roof means a cover with rim sealing mechanisms that rests upon and is supported by the liquid being contained and is equipped with a closure seal or seals to close the space between the roof edge and unit wall. A fixed roof means a cover that is mounted on a waste management unit in a stationary manner and that does not move with changes in the level of liquid in the unit. Title 40, Code of Federal Regulations, Section 61.341.

14. A closed-vent system is a system that is not open to the atmosphere and is composed of piping, ductwork, connections and, if necessary, flow inducing devices, such as fans or blowers, that transport vapors from an emission source to a control device. Title 40, Code of Federal Regulations, Section 61.341.

15. A closed-vent system that contains any bypass line that could divert the vent stream away from a control device used to comply with the requirements of the regulations must be equipped with a flow indicator that provides a record of vent stream flow away from the control device and indicates whether gas flow is present in a line or system except as provided in Title 40, Code of Federal Regulations, Section 61.349(a)(1)(ii)(B).

16. A control device means an enclosed combustion device, vapor recovery system or flare. Title 40, Code of Federal Regulations, Section 61.341. The purpose of a control device is to destroy or recover benzene emissions. The Thermatrix thermal oxidizer located at the West Plant was an example of a control device. When it worked effectively, the Thermatrix acted like a high temperature furnace and converted benzene and other hydrocarbons to carbon dioxide and water.

17. Openings in individual drain systems containing non-exempt benzene waste must be equipped with seals that prevent emissions of benzene into the atmosphere or be equipped with covers and closed-vent systems that route benzene vapors to control devices. Title 40, Code of Federal Regulations, Section 61.346.

18. Oil-water separators (sometimes referred to hereafter as separators) are waste management units which are used to separate oil from water. Title 40, Code of Federal Regulations, Section 61.341. The Edens and API separators at the West Plant were examples of oil-water separators. Separators that come in contact with non-exempt waste streams containing

benzene either must be covered or sealed, or must be maintained below atmospheric pressure and connected to a closed-vent system that routes all vapors to control devices. Title 40, Code of Federal Regulations, Section 61.347.

19. Regulations promulgated by EPA under authority of the Clean Air Act provide, in pertinent part, that ninety days after the effective date of any standard, no owner or operator shall operate any facility or installation subject to the standard in violation of that standard. Title 42, United States Code, Sections 7413(c)(1) and 7412(i)(3); Title 40, Code of Federal Regulations, Sections 61.05(c), 61.342(b).

20. On or about April 1993, the defendant **KOCH PETROLEUM GROUP, L.P.**, applied for and was granted a waiver of compliance until January 7, 1995, to comply with the benzene NESHAP regulations at the West Plant.

21. An owner or operator is any person who owns, leases, operates, controls or supervises a facility or installation. An operator includes a person who is senior management personnel or a corporate officer. Title 42, United States Code, Sections 7413(h), 7412(a)(9); Title 40, Code of Federal Regulations, Section 61.02.

22. The EPA authorized the State of Texas through the Texas Natural Resource Conservation Commission (TNRCC), previously known as the Texas Air Control Board and the Texas Water Commission, to implement and enforce the benzene NESHAP standards. The State of Texas has adopted the emissions standards for hazardous air pollutants promulgated by the EPA pursuant to the Federal Clean Air Act, Section 112, as amended. Title 30 Tex. Admin. Code., Section 101.20(2). Pursuant to the Clean Air Act, the EPA retains authority to enforce the benzene NESHAP and other regulations promulgated pursuant to the Clean Air Act. Title 42, United States Code, Section 7412(l).

THE DEFENDANTS

23. The defendant **KOCH INDUSTRIES, INC.**, owned defendant **KOCH PETROLEUM GROUP, L.P.** The corporate headquarters of **KOCH INDUSTRIES, INC.** is located in Wichita, Kansas. The defendant **KOCH INDUSTRIES, INC.**, through its agents and employees, operated and assisted in the operation of the West Plant.

24. The defendant, **KOCH PETROLEUM GROUP, L.P.**, previously known as Koch Refining Company L.P. or Koch Refining Company, operated a petroleum refinery located in Nueces County, Texas. At all times, the defendant **KOCH PETROLEUM GROUP, L.P.** acted on behalf of, in concert with and for the benefit of the defendant **KOCH INDUSTRIES, INC.** in operating the petroleum refinery located in Nueces County, Texas.

25. The defendant **DAVID L. LAMP** was the plant manager of the West Plant from in or about November 1991, until in or about June 1994, when he was promoted to Vice President for Marketing of the Koch Refining and Chemical Group. On or about May 15, 1996, he officially became Vice President of Texas Operations for Koch Refining Company, L.P., as defendant **KOCH PETROLEUM GROUP, L.P.**, was then known. During his employment, **DAVID L. LAMP'S** duties included, among other things, the operation and management of the petroleum refinery in Nueces County, Texas. The defendant **DAVID L. LAMP'S** duties also included involvement in the benzene NESHAP compliance issues at the petroleum refinery.

26. The defendant **VINCENT A. MIETLICKI** was an attorney employed in the Legal Department of the defendant **KOCH INDUSTRIES, INC.** The defendant **VINCENT A. MIETLICKI** was assigned to assist in the management of the benzene NESHAP compliance issues related to the petroleum refinery located in Nueces County, Texas. His duties included,

among other things, providing legal advice with respect to environmental matters at the West Plant. On or about May 15, 1996, the defendant **VINCENT A. MIETLICKI** officially assumed the position of Environmental Manager for the petroleum refinery, at which time his duties included, among other things, overall responsibility for the operation of the Environmental Department at the West and East plants.

27. The defendant **JOHN C. WADSWORTH** was employed by Koch Refining Company, L.P., as the defendant **KOCH PETROLEUM GROUP, L.P.** was then known, as the Vice President and Refinery Manager of the petroleum refinery in Nueces County, Texas from in or about June 1994, until in or about May 1996. His duties included, among other things, the overall responsibility for the operation of the West Plant.

28. The defendant **JAMES W. WEATHERS, JR.** was employed by Koch Refining Company, L.P., as the defendant **KOCH PETROLEUM GROUP, L.P.** was then known, as an environmental engineer in the Environmental Department of the West Plant from on or about June 1, 1992, until on or about March 1, 1996, when he was promoted to Manager of the Environmental Department at the West Plant. His duties included, among other things, the overall responsibility for the management and operation of the Environmental Department at the West Plant.

THE CONSPIRACY

29. Beginning at a date unknown to the Grand Jury and continuing until at least in or about July 1996, in the Southern District of Texas, and elsewhere, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC.,
KOCH PETROLEUM GROUP, L.P.,
DAVID L. LAMP,
VINCENT A. MIETLICKI,
JOHN C. WADSWORTH and
JAMES W. WEATHERS, JR.,**

together with others unknown to the Grand Jury did knowingly and willfully combine, conspire, confederate and agree to:

(a) Knowingly operate and cause the West Plant to be operated without complying with the benzene NESHAP promulgated under the Clean Air Act, in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.05(c) and Title 18, United States Code, Section 2 and,

(b) Knowingly and willfully make and cause to be made, false, fictitious and fraudulent statements and representations, and falsify, conceal and cover up, and cause to be falsified, concealed and covered up, by trick, scheme and device material facts in a matter within the jurisdiction of the Environmental Protection Agency, an agency of the United States, in violation of Title 18, United States Code, Sections 1001 and 2.

OBJECTS OF THE CONSPIRACY

30. It was an object of the conspiracy to prevent the EPA, the TNRCC, and the citizens of Nueces County, Texas, from learning that the West Plant was being operated without complying with the benzene NESHAP, and that the West Plant was emitting benzene into the atmosphere in violation of the law.

31. It was further an object of the conspiracy to avoid private civil lawsuits, administrative and civil actions, and criminal prosecution by concealing the fact that the West Plant was being operated in violation of the law.

32. It was further an object of the conspiracy to avoid or delay the financial expenditures necessary to comply with the law and to avoid shutting down the West Plant until it could be brought into compliance with the benzene NESHAP so as to maximize corporate profits. The defendant **KOCH PETROLEUM GROUP, L.P.**, and the defendant **KOCH INDUSTRIES, INC.** earned approximately \$176 million in net profits during the year 1995, and \$75 million during the year 1996 from the operation of the petroleum refineries in Nueces County, Texas.

MANNER AND MEANS OF ACCOMPLISHING THE CONSPIRACY

33. In order to accomplish the objectives of the conspiracy, the defendants

**KOCH INDUSTRIES, INC.,
KOCH PETROLEUM GROUP, L.P.,
DAVID L. LAMP,
VINCENT A. MIETLICKI,
JOHN C. WADSWORTH and
JAMES W. WEATHERS, JR.,**

and others unknown to the Grand Jury would and did use the following manner and means:

(a) To delay taking steps to come into compliance with the benzene NESHAP and to seek a waiver of the compliance deadline until January 7, 1995;

(b) To initially start up the Thermatrix thermal oxidizer, a major control device at the West Plant, only a few days before compliance with the benzene NESHAP was required, thus allowing no time to determine whether the control device was of sufficient capacity to serve its intended purpose to destroy benzene vapors from two separators;

(c) To disconnect the Thermatrix thermal oxidizer from the Edens separator, because the Thermatrix was of insufficient capacity to destroy benzene vapors from both the Edens and the API separators;

(d) To continue to cause wastewater which contained benzene to enter the Edens separator, with knowledge that the separator was not equipped with a control device, and that the benzene vapors were being vented to the atmosphere, after the West Plant exceeded the 6 megagram limit for uncontrolled benzene waste streams during 1995;

(e) To cause wastewater containing benzene at the West Plant to enter the API separator during periods when the separator's control device, the Thermatrix thermal oxidizer, was shut down, and to cause benzene emissions to vent directly into the atmosphere, after the West Plant exceeded the 6 megagram limit for uncontrolled benzene waste streams during 1995;

(f) To cause wastes containing benzene at the West Plant to flow through sewers not equipped with the required seals, covers, or control devices to prevent the emission of benzene into the atmosphere, with knowledge that the sewers were not equipped with required control devices, after the West Plant exceeded the 6 megagram benzene limit during 1995;

(g) To cause slop oil, sludge, and ballast water that contained benzene at the West Plant to be placed in tanks with knowledge that the tanks were not equipped to prevent emissions of benzene into the atmosphere, after the West Plant exceeded the 6 megagram benzene limit during 1995;

(h) To conceal material facts, including defendants' violations of the benzene NESHAP from the TNRCC, the EPA and the citizens of Nueces County, Texas, so that (i) the West Plant could continue to be operated, and (ii) the defendants would not face private civil suits, civil or criminal penalties, and (iii) the cost of equipping the West Plant to meet the standards, or the loss of profits that would result if the West Plant were shut down until it could meet the requirements of the benzene NESHAP;

(i) To file an annual report for 1995 that covered up the fact that the West Plant generated far more uncontrolled benzene during the year 1995 than the 6 megagrams allowed by the regulatory option chosen for the West Plant;

(j) To falsely inform the TNRCC that the West Plant was in continuous compliance with the benzene NESHAP requirements when the defendants well knew the West Plant was being operated in violation of those requirements.

OVERT ACTS

34. In furtherance of the conspiracy and to effect the objects of the conspiracy, the defendants **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.,** and others unknown to the Grand Jury, would and did commit and cause to be committed in the Southern District of Texas and elsewhere, the following overt acts:

(a) On or about July 15, 1992, the defendant **DAVID L. LAMP** placed a hold on parts of a construction project that were necessary to bring the West Plant into compliance with the benzene NESHAP;

(b) Having been advised in July 1992 that the defendant **KOCH PETROLEUM GROUP, L.P.** could meet the original NESHAP compliance deadline of March 1993, nonetheless, the defendant **DAVID L. LAMP** in or about February 1993, authorized the filing with the TNRCC of a request for a waiver, to delay the requirement to comply with the benzene NESHAP at the West Plant for two years, or until January 7, 1995.

(c) On or about January 28, 1994, the defendant **DAVID L. LAMP** authorized work to begin on a scaled-down version of the project to bring the West Plant into compliance with the benzene NESHAP. The scaled-down version of the project excluded certain

areas from control, including the West Crude Desalter sewer, the D Street sewer, the G Street sewer, Sludge Tanks 2104, 2105, and 2106 and Ballast Water Tank 109;

(d) The defendants **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** failed to control the waste streams in the West Plant from January 7, 1995, the date it was required to bring the West Plant into compliance with the benzene NESHAP;

(e) On or about January 4, 1995, the defendant **KOCH PETROLEUM GROUP, L.P.** first placed in service the Thermatrix thermal oxidizer, intended to be the control device for both the API and the Edens separators, without allowing enough time to determine whether the Thermatrix could serve as an effective control device for both separators;

(f) On or about January 6, 1995, the defendant **KOCH PETROLEUM GROUP, L.P.** certified pursuant to Title 40, Code of Federal Regulations, Section 61.356(f)(1) with respect to the Thermatrix thermal oxidizer that the closed-vent system and control device at the West Plant was designed to operate at the required performance level when the waste management unit vented to the control device was operating at the highest load or capacity expected to occur;

(g) In or about January 1995, the defendant **KOCH PETROLEUM GROUP, L.P.** constructed or caused to be constructed bypass stacks at the West Plant for the purpose of venting benzene vapors from the Edens and API oil-water separators directly into the atmosphere and thereby avoiding required control devices;

(h) On or about January 11, 1995 the defendant **VINCENT A. MIETLICKI** authorized employees of the defendant, **KOCH PETROLEUM GROUP, L.P.** to manage repeated failures of the Thermatrix thermal oxidizer as "upsets," to conceal the fact that

the Thermatrix was not of sufficient capacity to serve as a control device to destroy benzene emissions from the two separators;

(i) On or about April 7, 1995, the defendant **KOCH PETROLEUM GROUP, L.P.** filed the Benzene NESHAP Subpart FF Quarterly Report for the first quarter of 1995, which concealed the fact that none of the required tests had been performed during the first quarter 1995 on the waste streams entering the enhanced biodegradation unit at the wastewater treatment plant (herein referred to as the aeration basin) at the West Plant to determine the quantity of benzene in them;

(j) In or about May 1995, the defendant **JAMES W. WEATHERS, JR.** met with other employees of the defendant **KOCH PETROLEUM GROUP, L.P.** to discuss the results of sampling of the benzene waste stream flowing into the Edens separator. The sampling results and flow rate data indicated the West Plant had exceeded its 6 megagram limit for uncontrolled benzene waste streams;

(k) In or about May 1995, the defendant **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** decided to continue to operate the West Plant without taking steps necessary to control the waste streams leading to the Edens separator;

(l) In or about July 1995, the defendants **VINCENT A. MIETLICKI** and **JOHN C. WADSWORTH**, having learned that the Benzene NESHAP Subpart FF Quarterly Report for the first quarter of 1995 already filed with the TNRCC was false, in that none of the required tests to determine the concentration of benzene in the waste streams entering the aeration basin at the West Plant had been performed during the first quarter 1995, did not file a revised report as required by Title 40, Code of Federal Regulations, Section 61.05(d);

(m) On or about July 18, 1995, the defendant **JOHN C. WADSWORTH** attended a meeting with other employees of the defendant **KOCH PETROLEUM GROUP, L.P.**, at which time he reviewed sampling results from the Edens separator indicating noncompliance with the benzene NESHAP, and as plant manager continued to operate the West Plant without taking steps to control the waste streams;

(n) On or about August 2, 1995, the defendant **VINCENT A. MIETLICKI** authorized the filing of the Quarterly Report for the second quarter of 1995, worded so as not to disclose the fact that the defendant **KOCH PETROLEUM GROUP, L.P.** had not performed the required testing during the second quarter of 1995 to determine the concentration of benzene in waste streams entering the aeration basin;

(o) On or about August 16, 1995, the defendant **JOHN C. WADSWORTH** learned about the filing of the quarterly reports for the first and second quarters of 1995 with the TNRCC, which reports did not disclose the fact that the defendant **KOCH PETROLEUM GROUP, L.P.** had not tested as required during those quarters of 1995 to determine the concentration of benzene in waste streams entering the aeration basin. Defendant **JOHN C. WADSWORTH** did not revise or cause the Quarterly Reports to be revised as required by Title 40, Code of Federal Regulations, Section 61.05(d);

(p) On or about September 25, 1995, defendant **VINCENT A. MIETLICKI** retained an environmental consulting firm to evaluate whether the West Plant was in compliance with the benzene NESHAP;

(q) On or about October 5, 1995, the defendant **VINCENT A. MIETLICKI** was informed by the environmental consulting firm that the West Plant had exceeded the 6 megagram limit for 1995;

(r) On or about November 27, 1995, the defendants **VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.** on behalf of the defendants, **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.**, attended a meeting with representatives of the TNRCC in Austin, Texas, during which they concealed the extent to which the West Plant was out of compliance with the benzene NESHAP;

(s) In or about January 1996, the defendants **VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.** on behalf of the defendants, **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.**, met with another employee of the defendant **KOCH PETROLEUM GROUP, L.P.**, who informed them that the West Plant's total annual uncontrolled benzene quantity for the year 1995 was 91 megagrams and, therefore, the 6 megagram limit for 1995 had been exceeded;

(t) On or about February 6, 1996, the defendants **VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.** on behalf of the defendants **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** attended a meeting with representatives of the TNRCC in Austin, Texas, during which said defendants attending the meeting falsely stated that the West Plant was in compliance with the benzene NESHAP;

(u) On or about February 12, 1996, the defendants **VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.** on behalf of the defendants **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** attended a meeting with representatives of the TNRCC in Corpus Christi, Texas during which said defendants attending the meeting falsely represented that the West Plant was in compliance with the benzene NESHAP.

(v) On or about March 25, 1996, the defendant **VINCENT A. MIETLICKI** reviewed a draft of the 1995 Total Annual Benzene Report for the East Plant to be filed with the TNRCC, which draft contained a figure represented as the total annual uncontrolled benzene wastes generated at the East Plant during 1995, as required to be reported by the regulation. Title 40, Code of Federal Regulations, Section 61.357(d)(5);

(w) On or about April 8, 1996, the defendants **VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.** on behalf of the defendants, **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.**, transmitted and caused to be transmitted, a cover letter and an annual report for 1995 to the TNRCC. The documents did not report the correct total annual uncontrolled benzene wastes generated at the West Plant during 1995. The documents reported only 0.61 megagrams total of uncontrolled benzene at the West Plant. The report and the letter concealed the fact, which the defendants **DAVID L. LAMP, VINCENT A. MIETLICKI, JAMES W. WEATHERS, JR., KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.**, were required to reveal, that the West Plant had generated benzene waste in an amount greater than the 6 megagram limit for uncontrolled benzene waste streams;

(x) On or about April 18, 1996, the defendants **JAMES W. WEATHERS, JR.** and **VINCENT A. MIETLICKI** on behalf of the defendants, **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** delivered to a representative of the TNRCC a letter, signed by the defendant **JAMES W. WEATHERS, JR.**, which falsely stated that the West Plant was in continuous compliance with the benzene NESHAP, when, as the defendants, **JAMES W. WEATHERS, JR., VINCENT A. MIETLICKI, KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.**, well knew, the West Plant

was being and had been operated in violation of the benzene NESHAP;

All in violation of Title 18, United States Code, Section 371.

COUNTS 2-9

35. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

36. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly cause wastewater containing benzene to flow into an oil-water separator at the West Plant, known as the Edens separator, although they knew that the separator was not equipped with an emission control device to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
2	May 5-31, 1995
3	June 1-30, 1995
4	July 1-31, 1995
5	August 1-31, 1995
6	September 1-30, 1995
7	October 1-31, 1995
8	November 1-30, 1995
9	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.347; and Title 18, United States Code, Section 2.

COUNTS 10-17

37. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

38. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P..**

operators of the West Plant, did knowingly cause wastewater containing benzene to flow into oily water sewers at the West Plant, known as the G Street, D Street, and West Crude Desalter sewers, although they knew that these sewers were not sealed or equipped with emission control devices to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
10	May 5-31, 1995
11	June 1-30, 1995
12	July 1-31, 1995
13	August 1-31, 1995
14	September 1-30, 1995
15	October 1-31, 1995
16	November 1-30, 1995
17	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.346; and Title 18, United States Code, Section 2.

COUNTS 18-25

39. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

40. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly cause waste slop oil containing benzene to be placed in a slop oil tank at the West Plant, Tank 1004, although they knew that the tank was not equipped with emission control equipment to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
18	May 5-31, 1995
19	June 1-30, 1995
20	July 1-31, 1995
21	August 1-31, 1995
22	September 1-30, 1995
23	October 1-31, 1995
24	November 1-30, 1995
25	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.343; and Title 18, United States Code, Section 2.

COUNTS 26-33

41. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

42. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly cause waste slop oil containing benzene to be placed in a slop oil tank at the West Plant, Tank 1005, although they knew that the tank was not equipped with emission control equipment to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
26	May 5-31, 1995
27	June 1-30, 1995
28	July 1-31, 1995
29	August 1-31, 1995
30	September 1-30, 1995
31	October 1-31, 1995
32	November 1-30, 1995
33	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.343; and Title 18, United States Code, Section 2.

COUNTS 34-41

43. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

44. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly cause waste slop oil containing benzene to be placed in a slop oil tank at the West Plant, Tank 1006, although they knew that the tank was not equipped with emission control equipment to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams,

COUNT	DATES
34	May 5-31, 1995
35	June 1-30, 1995
36	July 1-31, 1995
37	August 1-31, 1995
38	September 1-30, 1995
39	October 1-31, 1995
40	November 1-30, 1995
41	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.343; and Title 18, United States Code, Section 2.

COUNTS 42-49

45. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

46. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly cause waste sludge containing benzene to be placed in a sludge tank at the West Plant, Tank 2104, although they knew that the tank was not equipped with emission control equipment to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled waste streams for 1995,

COUNT	DATES
42	May 5-31, 1995
43	June 1-30, 1995
44	July 1-31, 1995
45	August 1-31, 1995
46	September 1-30, 1995
47	October 1-31, 1995
48	November 1-30, 1995
49	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.343; and Title 18, United States Code, Section 2.

COUNTS 50-57

47. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

48. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

did knowingly cause waste sludge containing benzene to be placed in a sludge tank at the West Plant, Tank 2105, although they knew that the tank was not equipped with emission control

equipment to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
50	May 5-31, 1995
51	June 1-30, 1995
52	July 1-31, 1995
53	August 1-31, 1995
54	September 1-30, 1995
55	October 1-31, 1995
56	November 1-30, 1995
57	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.343; and Title 18, United States Code, Section 2.

COUNTS 58-65

49. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

50. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly cause waste sludge containing benzene to be placed in a sludge tank at the West Plant, Tank 2106, although they knew that the tank was not equipped with emission control equipment to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
58	May 5-31, 1995
59	June 1-30, 1995
60	July 1-31, 1995
61	August 1-31, 1995
62	September 1-30, 1995
63	October 1-31, 1995
64	November 1-30, 1995
65	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.343; and Title 18, United States Code, Section 2.

COUNTS 66-73

51. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

52. On or about the following dates in the Southern District of Texas and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P..**

operators of the West Plant, did knowingly cause wastewater containing benzene to be placed in a ballast water tank at the West Plant, Tank 109, although they knew that the tank was not equipped with emission control equipment to prevent benzene emissions into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
66	May 5-31, 1995
67	June 1-30, 1995
68	July 1-31, 1995
69	August 1-31, 1995
70	September 1-30, 1995
71	October 1-31, 1995
72	November 1-30, 1995
73	December 1-31, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.343; and Title 18, United States Code, Section 2.

COUNTS 74-85

53. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

54. The Thermatrix thermal oxidizer located at the West Plant was the control device for the API separator. At various times between January 4, 1995 and October 30, 1996, the Thermatrix thermal oxidizer was not operating.

55. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly cause wastewater containing benzene to flow into an oil-water separator at the West Plant, known as the API separator, although they knew that the vapor flow from the separator was not vented to a control device to prevent benzene emissions

into the atmosphere, after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
74	May 31-June 2, 1995
75	June 13-16, 1995
76	July 2-4, 1995
77	September 10-12, 1995
78	September 15-21, 1995
79	September 23-25, 1995
80	September 28-29, 1995
81	September 30-October 2, 1995
82	October 2-11, 1995
83	November 10-11, 1995
84	November 19-28, 1995
85	November 30-December 1, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.347; and Title 18, United States Code, Section 2.

COUNTS 86-88

56. Paragraphs 1 through 28 of Count One of this Indictment are hereby realleged and incorporated herein as though set forth in full.

57. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC.,
KOCH PETROLEUM GROUP, L.P.,
DAVID L. LAMP,
VINCENT A. MIETLICKI, and
JOHN C. WADSWORTH**

knowingly operated and caused to be operated the West Plant, a stationary source, in violation of the National Emission Standard for Waste Operations after the West Plant exceeded its 6 megagram limit for uncontrolled benzene waste streams for 1995,

COUNT	DATES
86	October 1995
87	November 1995
88	December 1995

All in violation of Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.05(c); and Title 18, United States Code, Section 2.

COUNTS 89-90

58. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

59. From on or about January 12, 1995 through December 31, 1995, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly operate and cause to be operated at the West Plant the following two bypass lines capable of diverting benzene vent stream away from a control device, which bypass lines were not equipped with flow indicators providing a record of vent stream flow away from the control device,

COUNT	LINE IDENTIFICATION NUMBER
89	4"-CAC-00-2191 (Manually Operated)
90	6"-CAC-00-2164 (Automatically Operated)

All in violation Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.349 and Title 18, United States Code, Section 2.

COUNTS 91-92

60. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

61. From on or about January 1, 1996 through December 31, 1996, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC. and
KOCH PETROLEUM GROUP, L.P.**

operators of the West Plant, did knowingly operate and cause to be operated at the West Plant the following two bypass lines capable of diverting benzene vent stream away from a control device, which bypass lines were not equipped with flow indicators providing a record of vent stream flow away from the control device.

COUNT	LINE IDENTIFICATION NUMBER
91	4"-CAC-00-2191 (Manually Operated)
92	6"-CAC-00-2164 (Automatically Operated)

All in violation Title 42, United States Code, Section 7413(c)(1); Title 40, Code of Federal Regulations, Section 61.349 and Title 18, United States Code, Section 2.

COUNTS 93-94

**THE COMPREHENSIVE ENVIRONMENTAL
RESPONSE, COMPENSATION AND LIABILITY ACT**

62. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

63. The Comprehensive Environmental Response, Compensation and Liability Act, Title 42, United States Code, Section 9601 et. seq. (CERCLA) makes it a criminal offense for a person or persons in charge of a facility to fail to notify immediately the National Response Center as soon as they have knowledge of an unpermitted release of a hazardous substance in excess of a reportable quantity. Title 42, United States Code, Section 9603(b)(3).

64. The term "facility" means any building, structure, installation, equipment or pipe. The West Plant was a "facility" within the meaning of CERCLA, Title 42, United States Code, Section 9601(9).

65. Congress and EPA have established that benzene is a "hazardous substance" as defined by Title 42, United States Code, Section 9601(14), 40 Code of Federal Regulations, Section 61.01(a) and Section 302.4.

66. Pursuant to the authority granted to it, EPA promulgated regulations establishing the quantity of benzene that, when released, may present substantial danger to the public health or welfare or the environment. Title 42, United States Code, Section 9602.

67. EPA established a reportable quantity of benzene of 10 pounds within a 24-hour period, based upon benzene's potential for causing cancer. 40 Code of Federal Regulations, Sections 302.4 (table, note a); 54 Federal Register 33418 (1989).

68. By at least October 9, 1995, the defendants **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** had in their possession certain Performance Testing data for the Thermatrix thermal oxidizer which data established that at least 24 pounds of benzene per hour were entering the vent stream intended to be processed by the Thermatrix.

69. The defendants **KOCH PETROLEUM GROUP, L.P.**, and **KOCH INDUSTRIES, INC.** were each a "person in charge of a facility" from which benzene, a hazardous substance, was released, as defined by CERCLA. 42 United States Code, Section 9601 (9) and 9601(21).

70. On or about July 2 through July 4, 1995, September 10 through September 12, 1995, September 15 through September 21, 1995, September 23 through September 25, 1995, September 28 through September 29, 1995, and September 30, 1995 a reportable quantity of benzene, a hazardous substance, was released into the atmosphere from the API separator at the West Plant. The defendants **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** became aware of the releases based upon the assembly of information necessary for filing the quarterly report for the third quarter of 1995.

71. On or about October 1 through October 2, 1995, October 2 through October 11, 1995, November 10 through November 11, 1995, November 19 through November 28, 1995, and November 30 through December 1, 1995, reportable quantities of benzene, a hazardous substance, were released into the atmosphere from the API separator at the West Plant. The defendants **KOCH INDUSTRIES, INC.** and **KOCH PETROLEUM GROUP, L.P.** became aware of the releases based upon the assembly of information necessary for filing the quarterly report for the fourth quarter of 1995.

72. On or about the following dates, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH PETROLEUM GROUP, L.P., and
KOCH INDUSTRIES, INC.**

operators of the West Plant and each a person in charge of the West Plant, failed to report the release of a reportable quantity of benzene, a hazardous substance, to the National Response Center, the appropriate agency of the United States, as soon as the defendants had knowledge of the release,

COUNT	DATES
93	October 25, 1995
94	January 26, 1996

All in violation of Title 42, United States Code, Section 9603(b) and Title 18, United States Code, Section 2.

COUNT 95

73. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

74. On or about February 6, 1996, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC.,
KOCH PETROLEUM GROUP, L.P.,
VINCENT A. MIETLICKI, and
JAMES W. WEATHERS**

in a matter within the jurisdiction of the Environmental Protection Agency, an agency of the United States, knowing and willfully made and caused to be made, a materially false, fictitious and fraudulent statement and representation in that the defendants stated to the TNRCC that the West Plant was in compliance with the benzene NESHAP prior to 1996 when in truth and in fact, the defendants then and there well knew that the West Plant had exceeded the 6 megagram limit for 1995,

All in violation of Title 18, United States Code, Section 1001 and 2.

COUNT 96

75. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

76. On or about April 8, 1996, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC.,
KOCH PETROLEUM GROUP, L.P.,
DAVID L. LAMP
VINCENT A. MIETLICKI, and
JAMES W. WEATHERS, JR.,**

in a matter within the jurisdiction of the Environmental Protection Agency, an agency of the United States, knowingly and willfully falsified, concealed and covered up and caused the falsification, concealment and cover up by trick, scheme and device, a material fact in that the

defendants, **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., DAVID L. LAMP, VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.** filed a report stating that the West Plant generated 0.61 megagrams of uncontrolled benzene waste, thereby concealing and covering up the material fact that the West Plant generated benzene waste in an amount greater than the 0.61 megagrams of uncontrolled benzene waste during 1995, a fact they were obliged to reveal,

All in violation of Title 18, United States Code, Sections 1001 and 2.

COUNT 97

77. Paragraphs 1 through 28 of Count One are hereby realleged and incorporated herein as though set forth in full.

78. On or about April 18, 1996, in the Southern District of Texas, and within the jurisdiction of the Court, the defendants,

**KOCH INDUSTRIES, INC.,
KOCH PETROLEUM GROUP, L.P.,
VINCENT A. MIETLICKI, and
JAMES W. WEATHERS, JR.,**

in a matter within the jurisdiction of the Environmental Protection Agency, an agency of the United States, knowingly and willfully falsified, concealed and covered up and caused the falsification, concealment and cover up by trick, scheme and device a material fact, in that they stated to the TNRCC in a letter dated April 18, 1996, that the West Plant was in continuous

compliance with the benzene NESHAP, when in truth and in fact, as the defendants, **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., VINCENT A. MIETLICKI, and JAMES W. WEATHERS, JR.**, well knew, the West Plant was then being operated in violation of the benzene NESHAP,

All in violation of Title 18, United States Code, Sections 1001 and 2.

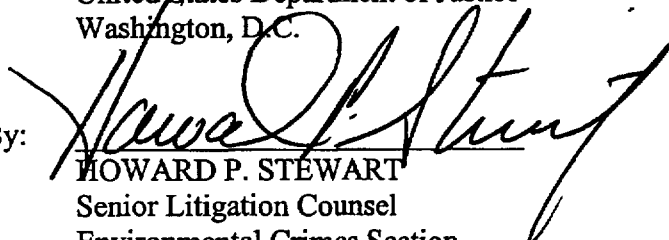
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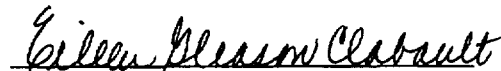
A TRUE BILL:

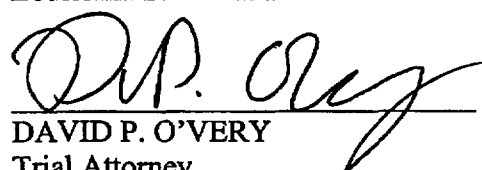

FOREPERSON OF THE GRAND JURY

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52

United States District Court
Southern District of Texas
FILED

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION

JAN 11 2001

MICHAEL N. MILBY, CLERK

UNITED STATES OF AMERICA

v.

KOCH INDUSTRIES, INC.

KOCH PETROLEUM GROUP, L.P.

DAVID L. LAMP

VINCENT A. MIETLICKI

JOHN C. WADSWORTH

JAMES W. WEATHERS, JR.

Defendants

CR C-00-325

SUPERSEDING INDICTMENT

18 U.S.C. § 371 (Conspiracy)

42 U.S.C. § 7413(c)(1)
(Violation of the Clean Air Act
Emission Standards, 40 C.F.R.
§ 61.342(e))

42 U.S.C. § 9603(b)
(Failure to Report Release of
Hazardous Substance)

18 U.S.C. § 1001 (False Statements)

18 U.S.C. § 2 (Aiding and Abetting)

THE GRAND JURY CHARGES THAT:

COUNT 1

At all times material to this Indictment:

1. The defendants **KOCH INDUSTRIES, INC.**, and **KOCH PETROLEUM GROUP, L.P.**, through their agents and employees, owned and operated a petroleum refinery in Nueces County, Texas, which was located on Suntide Road (the "West Plant").

2. Defendant **KOCH INDUSTRIES, INC.**, owned defendant **KOCH PETROLEUM GROUP, L.P.** In connection with operations at the West Plant, the defendant

TRUE COPY I CERTIFY
ATTEST: 4-5-01
MICHAEL N. MILBY, Clerk of Court
By Donna I. Small
Deputy Clerk

KOCH PETROLEUM GROUP, L.P. acted on behalf of, in concert with, and for the benefit of the defendant **KOCH INDUSTRIES, INC.**

3. Operations at the West Plant were subject to environmental regulations adopted by the United States Environmental Protection Agency ("EPA") under the authority of the federal Clean Air Act. Those regulations included National Emissions Standards for Hazardous Air Pollutants for waste operations which applied to benzene contaminated waste streams at the West Plant ("benzene NESHAP").

4. The federal Clean Air Act prohibits the operation of a stationary source like the West Plant in violation of the benzene NESHAP.

5. The defendants **DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.,** were employees of **KOCH INDUSTRIES, INC.,** or **KOCH PETROLEUM GROUP, L.P.,** who had authority to affect compliance with the benzene NESHAP at the West Plant and at various times during their employment, each participated in and were otherwise engaged in activities which affected the West Plant's compliance with the benzene NESHAP.

6. The EPA had delegated responsibility to the State of Texas to implement and enforce the benzene NESHAP. Pursuant to the federal Clean Air Act, the EPA retained authority to enforce the benzene NESHAP.

7. The defendants **DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.,** each participated in and otherwise was engaged in activities intended to misrepresent and conceal violations of the benzene NESHAP at the West Plant from the Texas Natural Resource Conservation Commission ("TNRCC").

A. THE CONSPIRACY

8. From on or about January 1, 1995, and continuing until on or about May 31, 1996, both dates being approximate and inclusive, in the Southern District of Texas, and elsewhere within the jurisdiction of the Court, the defendants, **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.**, did knowingly and willfully conspire with each other, and with others known and unknown to the Grand Jury, to commit the following offenses against the United States:

(a) To knowingly operate the West Plant in a manner which violated the emission standard found at Title 40, Code of Federal Regulations, Section 61.342(e) in violation of Title 42, United States Code, Section 7413(c)(1) and Title 18, United States Code Section 2; and

(b) To knowingly and willfully misrepresent and conceal material matters within the jurisdiction of the United States Environmental Protection Agency in violation of Title 18, United States Code, Section 1001 and Title 18, United States Code Section 2.

B. MANNER AND MEANS OF ACCOMPLISHING THE CONSPIRACY

9. The defendants and others known and unknown to the Grand Jury used the following manner and means to accomplish the conspiracy:

(a) It was part of the conspiracy to knowingly operate the West Plant such that the annual uncontrolled benzene quantity in its wastewater did not comply with the emission standard found at Title 40, Code of Federal Regulations, Section 61.342(e).

(b) It was an ongoing and continuous part of the conspiracy to knowingly and willfully misrepresent and conceal any information which would reveal that the uncontrolled benzene quantity in the wastewater at the West Plant exceeded the 6 megagram limit during 1995.

C. **OVERT ACTS**

10. In order to help the conspiracy succeed, avoid detection and accomplish its goals, at least one of the conspirators committed, and caused to be committed, one or more of the following acts in the Southern District of Texas and elsewhere. The list of overt acts set forth in this Superseding Indictment does not exhaust all of the overt acts which may be shown at trial:

(a) On or about January 6, 1995, a West Plant employee sent a letter to the TNRCC certifying that all equipment necessary to comply with the emission standard at Title 40, Code of Federal Regulations, Section 61.342(e) had been installed at the West Plant.

(b) On or about January 6, 1995, an employee at the West Plant signed a document which certified that the control equipment for the oil-water separators at the West Plant had been designed to operate "at the relevant performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur."

(c) On or about January 7, 1995, employees at the West Plant disconnected the control device for the Edens oil-water separator at the West Plant.

(d) On or about January 11, 1995, **VINCENT A. MIETLICKI** directed employees under his supervision and control to report failures of the control device for the oil-water separators at the West Plant to the TNRCC as "upsets."

(e) On or about January 12, 1995, employees at the West Plant constructed and caused to be constructed a line designed to bypass the control device for the Edens oil-water separator at the West Plant.

(f) On or about March 2, 1995, employees at the West Plant caused benzene contaminated wastewater to flow into the Edens oil-water separator when it did not have a control device.

(g) On or about April 7, 1995, an employee of the West Plant filed a report which concealed the fact that during the first quarter of 1995, waste streams entering the aeration basin at the West Plant had not been tested to determine the quantity of benzene in them.

(h) On or about April 15, 1995, employees at the West Plant caused benzene contaminated wastewater to flow into the Edens oil-water separator when it did not have a control device.

(i) On or about May 5, 1995, **JAMES W. WEATHERS, JR.**, attended a meeting and there received information which showed that the uncontrolled benzene quantity in wastewater at the West Plant had exceeded 6 megagrams during 1995.

(j) On or about July 18, 1995, **JOHN C. WADSWORTH** and **JAMES W. WEATHERS, JR.**, attended meetings and there received information which showed that the uncontrolled benzene quantity in wastewater at the West Plant had exceeded 6 megagrams in 1995.

(k) On or about August 2, 1995, a West Plant employee filed a report which concealed the fact that during the second quarter of 1995, waste streams entering the aeration basin at the West Plant had not been tested to determine the quantity of benzene in them.

(l) On or about August 7, 1995, employees at the West Plant caused benzene contaminated wastewater to flow into the Edens oil-water separator when it did not have a control device.

(m) On or about September 5, 1995, employees at the West Plant caused benzene contaminated wastewater to flow into the Edens oil-water separator when it did not have a control device.

(n) On or about October 5, 1995, **VINCENT A. MIETLICKI** reviewed and commented on a report from a private consultant which showed that the uncontrolled benzene

quantity in wastewater at the West Plant had exceeded 6 megagrams in 1995.

(o) On or about October 6, 1995, **VINCENT A. MIETLICKI** met with a private consultant and discussed a report which showed that the uncontrolled benzene quantity in wastewater at the West Plant had exceeded 6 megagrams in 1995.

(p) On or about October 12, 1995, **DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.,** attended a meeting and there discussed a report that the flameless thermal oxidizer was undersized and was down.

(q) On or about October 12, 1995, **DAVID L. LAMP** wrote that the uncontrolled benzene quantity in wastewater at the West Plant was over 6 tons and noted reliability problems for the control device.

(r) On or about October 26, 1995, **VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.,** attended a meeting and there discussed that the flameless thermal oxidizer was down and that the uncontrolled benzene quantity in the wastewater at the West Plant had exceeded 6 megagrams in 1995.

(s) On or about October 30, 1995, employees at the West Plant caused benzene contaminated wastewater to flow into the Edens oil-water separator when it did not have a control device.

(t) On or about November 6, 1995, employees at the West Plant caused benzene contaminated wastewater to flow into the Edens oil-water separator when it did not have a control device.

(u) On or about November 13, 1995, **VINCENT A. MIETLICKI** sent to **JOHN C. WADSWORTH** a memorandum written by **JAMES W. WEATHERS, JR.,** stating that the Edens oil-water separator was uncontrolled, the flameless thermal oxidizer was undersized, and that the

uncontrolled benzene quantity in the wastewater at the West Plant had exceeded 6 megagrams in 1995.

(v) On or about November 20, 1995, **DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.**, discussed the explanations they planned to make regarding noncompliance with the benzene NESHAP.

(w) On or about November 27, 1995, **VINCENT A. MIETLICKI and JAMES W. WEATHERS, JR.**, attended a meeting with representatives of the TNRCC in Austin, Texas, and misrepresented the extent to which the West Plant was out of compliance with the benzene NESHAP.

(x) On or about November 30, 1995, **DAVID L. LAMP and JOHN C. WADSWORTH** attended a meeting at which a West Plant employee told them that the West Plant was out of compliance with the benzene NESHAP.

(y) On or about December 18, 1995, employees at the West Plant caused benzene contaminated wastewater to flow into the Edens oil-water separator when it did not have a control device.

(z) On or about December 29, 1995, West Plant employees sent to **DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH, and JAMES W. WEATHERS, JR.**, a memorandum stating that the uncontrolled benzene quantity in wastewater at the West Plant had exceeded 6 megagrams in 1995.

(aa) On or about January 1, 1996, **VINCENT A. MIETLICKI** reviewed a report from a private consultant which showed that the uncontrolled benzene quantity in wastewater at the West Plant had exceeded 6 megagrams during 1995.

(bb) On or about January 4, 1996, a West Plant employee sent to **VINCENT A.**

MIETLICKI a memorandum stating that the uncontrolled benzene quantity in wastewater at the West Plant exceeded 6 megagrams in 1995.

(cc) On or about February 6, 1996, defendants **VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.**, attended a meeting with representatives of the TNRCC in Austin, Texas, and misrepresented information concerning compliance with the benzene NESHAP at the West Plant.

(dd) On or about February 12, 1996, defendants **VINCENT A. MIETLICKI** and **JAMES W. WEATHERS, JR.**, attended a meeting with representatives of the TNRCC in Corpus Christi, Texas, and misrepresented information concerning compliance with the benzene NESHAP at the West Plant.

(ee) On or about April 8, 1996, **JAMES W. WEATHERS, JR.**, filed a document with the TNRCC which misrepresented the amount of uncontrolled benzene in wastewater at the West Plant.

(ff) On or about April 18, 1996, defendants **JAMES W. WEATHERS, JR.**, and **VINCENT A. MIETLICKI** delivered a document to a representative of the TNRCC which misrepresented information concerning compliance with the benzene NESHAP at the West Plant.

All in violation of Title 18, United States Code, Section 371.

COUNTS 2-4

11. Paragraphs 1 through 6 of Count 1 of the superseding indictment are alleged as if set forth in full.

12. On or about the following dates, in the Southern District of Texas, and elsewhere within the jurisdiction of the Court, the defendants, **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., DAVID L. LAMP, VINCENT A. MIETLICKI** and **JOHN C.**

WADSWORTH, were owners or operators of the West Plant and knowingly operated and caused to be operated the West Plant when they knew that on or before that date the 1995 annual uncontrolled benzene quantity in the wastewater at the plant had exceeded 6 megagrams. The manner in which the defendants operated the West Plant on or about the dates alleged violated an applicable National Emissions Standard for Hazardous Air Pollutants; namely, Title 40 Code of Federal Regulations, Section 61.342(e):

Count 2 On or about October 26, 1995

Count 3 On or about November 20, 1995

Count 4 On or about December 1, 1995

All in violation of Title 42, United States Code, Section 7413(c)(1) and Title 18, United States Code, Section 2.

COUNT 5

13. Paragraphs 1 through 7 of Count 1 of the superseding indictment are alleged as if set forth in full.

14. On or about February 6, 1996, in the Southern District of Texas and elsewhere within the jurisdiction of the Court, the defendants, **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH** and **JAMES W. WEATHERS, JR.**, did knowingly and willfully make and cause to be made a false, fictitious and fraudulent statement and representation as to material matters within the jurisdiction of the United States Environmental Protection Agency, to wit: on or about that date they told the TNRCC that they had found all sources of benzene and had eliminated or controlled them and that they were no longer putting hydrocarbons, including benzene, into the sewers at the West Plant.

In violation of Title 18, United States Code, Section 1001 and Title 18, United States Code,

Section 2.

COUNT 6

15. Paragraphs 1 through 7 of Count 1 of the superseding indictment are alleged as if set forth in full.

16. On or about April 8, 1996, in the Southern District of Texas, and elsewhere within the jurisdiction of the Court, the defendants, **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH** and **JAMES W. WEATHERS, JR.**, did knowingly and willfully make and cause to be made a false, fictitious and fraudulent statement and representation as to material matters within the jurisdiction of the United States Environmental Protection Agency, to wit: on or about that date, they submitted and caused to be submitted a report to the TNRCC which represented that the annual benzene quantity in uncontrolled streams at the West Plant was 0.61 megagrams.

In violation of Title 18, United States Code, Section 1001 and Title 18, United States Code, Section 2.

COUNT 7

17. Paragraphs 1 through 7 of Count 1 of the superseding indictment are alleged as if set forth in full.

18. On or about April 18, 1996, in the Southern District of Texas, and elsewhere within the jurisdiction of the Court, the defendants, **KOCH INDUSTRIES, INC., KOCH PETROLEUM GROUP, L.P., DAVID L. LAMP, VINCENT A. MIETLICKI, JOHN C. WADSWORTH** and **JAMES W. WEATHERS, JR.**, did knowingly and willfully make and cause to be made a false, fictitious and fraudulent statement and representation as to material matters within the jurisdiction of the United States Environmental Protection Agency, to wit: on or about April 18, 1996, they

stated and caused to be stated in a letter to the TNRCC, that the West Plant refinery "maintains continuous compliance with the regulatory requirements of Benzene NESHAPS Subpart FF."

In violation of Title 18, United States Code, Section 1001 and Title 18, United States Code, Section 2.

COUNTS 8-9

19. The defendants **KOCH INDUSTRIES, INC.**, and **KOCH PETROLEUM GROUP, L.P.** were each a "person in charge of a facility" from which benzene, a hazardous substance, was released.

20. A reportable quantity of benzene is 10 pounds within a twenty-four hour period.

21. On or about October 9, 1995, the defendants **KOCH INDUSTRIES, INC.**, and **KOCH PETROLEUM GROUP, L.P.** had in their possession certain Performance Testing data for the flameless thermal oxidizer which data established that at least 10 pounds of benzene per day were entering the vent stream intended to be processed by the flameless thermal oxidizer.

22. On or about July 2 through July 4, 1995, September 10 through September 12, 1995, September 15 through September 21, 1995, September 23 through September 25, 1995, September 28 through September 29, 1995, and September 30, 1995 a reportable quantity of benzene, a hazardous substance, was released into the atmosphere from the API oil-water separator at the West Plant. The defendants **KOCH INDUSTRIES, INC.**, and **KOCH PETROLEUM GROUP, L.P.** became aware of the releases, at the latest, upon the assembly of information necessary for filing the quarterly report for the third quarter of 1995, which report was completed on or about October 25, 1995.

23. On or about October 1 through October 2, 1995, October 2 through October 11, 1995, November 10 through November 11, 1995, November 19 through November 28, 1995, and

November 30 through December 1, 1995, reportable quantities of benzene, a hazardous substance, were released into the atmosphere from the API oil-water separator at the West Plant. The defendants **KOCH INDUSTRIES, INC.**, and **KOCH PETROLEUM GROUP, L.P.** became aware of the releases, at the latest, upon the assembly of information necessary for filing the quarterly report for the fourth quarter of 1995, which report was completed on or about January 29, 1996.

24. On or about the following dates in the Southern District of Texas, and within the jurisdiction of the Court, the defendants, **KOCH INDUSTRIES, INC.**, and **KOCH PETROLEUM GROUP, L.P.**, operators of the West Plant and each a person in charge of the West Plant, failed to report the release of a reportable quantity of benzene, a hazardous substance, to the National Response Center, the appropriate agency of the United States, as soon as the defendants had knowledge of the release;

Count 8 On or about October 25, 1995

Count 9 On or about January 29, 1996

All in violation of Title 42, United States Code, Section 9603(b) and Title 18, United States Code, Section 2.

DATED:

1-11-01

A TRUE BILL:


FOREPERSON OF THE GRAND JURY

LOIS J. SCHIFFER
Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

United States District Court
Southern District of Texas
FILED

UNITED STATES DISTRICT COURT FOR THE
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION

MAR 16 2001

MICHAEL N. MILBY, CLERK

UNITED STATES OF AMERICA)

v.)

CRIM. NO. C-00-325(S)

Hon. Janis Graham Jack

KOCH INDUSTRIES, INC.)

KOCH PETROLEUM GROUP, L.P.)

DAVID L. LAMP)

VINCENT A. MIETLICKI)

JOHN C. WADSWORTH)

JAMES W. WEATHERS, JR.)

UNITED STATES' MOTION TO DISMISS COUNTS 8 AND 9

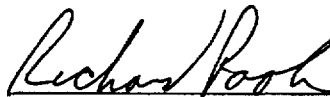
The United States, by and through its undersigned attorney, respectfully moves the Court to Dismiss Counts Eight and Nine of the Superseding Indictment without prejudice, and submits that dismissing Counts Eight and Nine is in the interests of justice. In support, the United States submits that Federal Rule of Criminal Procedure 48(a) provides that the government may dismiss counts of a multi-count indictment, with the leave of the Court and without the consent of defendants, at any time before trial. See, Thomas v. United States, 398 F.2d 53, 536-537 (5th Cir. 1968).

WHEREFORE, the United States moves the Court to enter the attached order.

JOHN C. CRUDEN

Acting Assistant Attorney General

Environment and Natural Resources Division



RICHARD POOLE, Attorney In Charge

DC Bar No. 295360

Environmental Crimes Section

U.S. Department of Justice

P.O. Box 23985, Washington, D.C. 20026

(202) 514-0838

March 16, 2001

TRUE COPY I CERTIFY

ATTEST: 9-5-01

MICHAEL N. MILBY, Clerk of Court

By Donna Tressell
Deputy Clerk

350

**UNITED STATES DISTRICT COURT FOR THE
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION**

UNITED STATES OF AMERICA)	
)	
v.)	CRIM. NO. C-00-325(S)
)	Hon. Janis Graham Jack
KOCH INDUSTRIES, INC.)	
KOCH PETROLEUM GROUP, L.P.)	
DAVID L. LAMP)	
VINCENT A. MIETLICKI)	
JOHN C. WADSWORTH)	
JAMES W. WEATHERS, JR.)	

ORDER

The United States' Motion to Dismiss Counts 8 and 9 is granted. Counts 8 and 9 are hereby DISMISSED, without prejudice.

Dated, this _____ day of _____, 2001.

UNITED STATES DISTRICT JUDGE

**UNITED STATES DISTRICT COURT FOR THE
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION**

UNITED STATES OF AMERICA

Y.

KOCH INDUSTRIES, INC.
KOCH PETROLEUM GROUP, L.P.
DAVID L. LAMP
VINCENT A. MIETLICKI
JOHN C. WADSWORTH
JAMES W. WEATHERS, JR.

CRIM. NO. C-00-325(S)
Hon. Janis Graham Jack

CERTIFICATE OF CONSULTATION

I certify that I have consulted with Defendants regarding the foregoing motion through lead counsel Jane F. Barrett, and that the parties were unable to reach agreement concerning the motion.

Richard Pook

RICHARD POOLE
Attorney In Charge

CERTIFICATE OF SERVICE

The undersigned hereby certifies that copies of the foregoing were served on the persons listed below, via telecopier and Federal Express on March 16, 2001:

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CANALES & SIMONSON
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P.O. Box 5624
Corpus Christi, TX 78465

Michael Levy
SWIDLER, BERLIN, SHEREFF, FRIEDMAN
3000 K Street, N.W., Suite 300
Washington, D.C. 20007-5116

**Attorney for Defendants
Koch Industries, Inc. and
Koch Petroleum Group, L.P.**

Of Counsel

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Koch Petroleum Group, L.P.**

**Attorney-in-Charge for Defendant
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David S. Krakoff
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**Attorney-in-Charge for Defendant
Vincent A. Mietlicki**

**Attorney-in-Charge for Defendant
John Wadsworth**

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Washington, D.C. 20036

Henry F. Schuelke, III
JANIS, SCHUELKE & WECHSLER
1728 Massachusetts Ave., N.W.
Washington, D.C. 20036

**Attorney-in-Charge for Defendant
Koch Industries, Inc.**

**Attorney-in-Charge for Defendant
James W. Weathers, Jr.**


RICHARD POOLE

Attorney-in-Charge
Senior Trial Attorney
Environmental Crimes Section

United States District Court
Southern District of Texas
ENTERED

UNITED STATES DISTRICT COURT FOR THE
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION

MAR 19 2001

Michael N. Milby, Clerk of Court

UNITED STATES OF AMERICA)

v.)

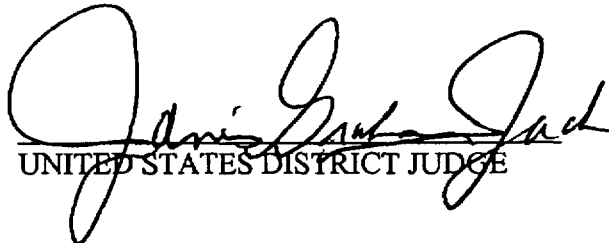
CRIM. NO. C-00-325(S)
Hon. Janis Graham Jack

KOCH INDUSTRIES, INC.)
KOCH PETROLEUM GROUP, L.P.)
DAVID L. LAMP)
VINCENT A. MIETLICKI)
JOHN C. WADSWORTH)
JAMES W. WEATHERS, JR.)

ORDER

The United States' Motion to Dismiss Counts 8 and 9 is granted. Counts 8 and 9 are hereby DISMISSED, without prejudice.

Dated, this 16th day of March, 2001.


UNITED STATES DISTRICT JUDGE

TRUE COPY I CERTIFY

ATTEST: 9-5-01

MICHAEL N. MILBY, Clerk of Court

By Donna Terrell
Deputy Clerk

356

53

United States District Court
Southern District of Texas
FILED

APR - 9 2001

MICHAEL N. MILBY
CLERK

UNITED STATES DISTRICT COURT FOR THE
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION

ORIGINAL

UNITED STATES OF AMERICA)

v.)

CRIM. NO. C-00-325(S)S
Hon. Janis Graham Jack

KOCH PETROLEUM GROUP, L.P.)

MEMORANDUM OF PLEA AGREEMENT

1. AGREEMENT: The Defendant knowingly and voluntarily agrees with the United States, by and through the undersigned, to:

A. Waive indictment and any applicable statute of limitations defense as to Count One of the attached Information; and

B. Plead guilty to Count One of the attached Information, which charges that Defendant concealed material facts in a matter within the jurisdiction of the Texas Natural Resources Conservation Commission and the United States Environmental Protection Agency between January 7, 1995, and April 7, 1995, to wit, the facts that a control device, the flameless thermal oxidizer known as the Thermatrix, had been disconnected from the Edens separator, a source of benzene vapors, and that defendants had failed to measure the level of benzene entering the aeration basin at the West Plant, all in violation of 18 U.S.C. 1001. Defendant admits that the United States can prove the facts set forth in the attached Factual Basis, and agrees that they are sufficient to support entry of a judgment of conviction.

TRUE COPY I CERTIFY

ATTEST: 9-5-01

MICHAEL N. MILBY, Clerk of Court

By Donna Terrell
Deputy Clerk

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2. JOINT RECOMMENDATION REGARDING SENTENCE: The United States and Defendant Koch Petroleum Group, L.P. ("KPGLP") agree pursuant to Rule 11(e)(1)(C) of the Federal Rules of Criminal Procedure that, upon entry of a guilty plea by defendant, the appropriate disposition of this case shall be as follows:

A. Defendant shall pay a fine of 10 million dollars (\$10,000,000). In addition, KPGLP shall pay a special assessment in the amount of four hundred dollars (\$400).

B. Defendant shall be placed on probation for five (5) years and, in addition to the standard terms and conditions of probation imposed by the Court, agrees to the following:

1. Defendant shall perform community service pursuant to §8B1.3 of the Federal Sentencing Guidelines and 18 U.S.C. § 3553(a). To fulfill this obligation Defendant shall pay, in addition to the fine described in Paragraph 2A, a total of 10 million dollars (\$10,000,000) (the "Community Service Funds") to the Clerk of the United States District Court, to be used for air or water quality remediation projects in and around the city of Corpus Christi, Texas.

Community service projects shall be proposed by the Defendant in consultation with the Texas Natural Resource Conservation Commission and the United States Environmental Protection Agency, and shall be subject to the agreement of the Environmental Crimes Section of the United States Department of Justice and approval by the Court. The Clerk of the Court shall release funds, upon application by Defendant, only for expenditures on such approved community service projects. Defendant agrees that it will not seek any reduction in its tax obligations as a result of its payment, and that it will not characterize, publicize, or refer to the payment as anything other than a community service payment made as a condition of probation incidental to a criminal conviction.

2. Defendant shall comply with all terms and conditions of the consent decree, as ultimately entered by the District Court, in United States v. Koch Petroleum Group, L.P., Civil Action No. 00-CV-2756 (D.Minn. 2000), that relate to the KPGLP East and West Corpus Christi refineries; however, Defendant will not be subject to probation revocation proceedings based on this consent decree unless, per the procedures provided for in said consent decree, the United States District Court for the District of Minnesota enters an order finding Defendant in contempt based on conduct occurring at the Corpus Christi refineries.

3. DISMISSAL OF INDICTMENTS: The Government agrees to move to dismiss, with prejudice, the original indictment and the superseding indictment in United States v. Koch Industries Inc., et al, Crim No. C-00-325, as to Koch Industries, Inc, KPGLP, David L. Lamp, Vincent A. Mietlicki, John C. Wadsworth, and James W. Weathers, Jr., after sentencing and entry of judgment against KPGLP, provided that the following terms of this plea agreement have been met:

A. KPGLP shall provide to the Court and undersigned representatives of the United States a corporate resolution by Defendant's Board of Directors which authorizes a plea of guilty to the charges in the Information, and binds KPGLP to this plea agreement;

B. Acceptance of this plea agreement by the Court;

C. Payment of the fine and special assessment amount by the Defendant to the United States District Court Clerk's Office at Corpus Christi, Texas, pursuant to Paragraph 2A, above.

D. Payment of the community service amount to the Clerk of the United States District Court for deposit into an interest-bearing escrow account, pursuant to Paragraph 2B1, above.

4. SENTENCING AND APPEAL: Defendant and the United States waive preparation of

a Presentence Investigation report. KPGLP and the United States agree that Plea and Sentencing may occur on the same date. KPGLP and the United States acknowledge that the Court, in its discretion, may order the preparation of such report and set a separate sentencing date without voiding this agreement. Defendant further agrees that if the Court accepts this agreement it waives the right to appeal its conviction and the sentence imposed in this case.

5. OTHER CRIMINAL MATTERS: KPGLP and the United States agree that this Plea Agreement constitutes a final resolution of all criminal matters relating to KPGLP's Corpus Christi facilities, presently known to the United States, concerning environmental crimes and Title 18 offenses relating to environmental crimes.

6. NO LIMITATION ON CIVIL AND ADMINISTRATIVE ACTIONS: KPGLP understands and agrees that nothing in this agreement shall limit the right of any agency or office of the United States, including but not limited to the United States Environmental Protection Agency, to take civil or administrative action, including any such action relating to suspension and debarment or listing; however, the Department of Justice agrees that it will not oppose, and will provide relevant information in support of a request by defendant for removal from suspension or debarment or listing, if such occurs.

7. COURT NOT BOUND BY THIS AGREEMENT: The United States and Defendant agree to be bound by the terms of this agreement, but understand that the Court may accept or reject this agreement, or defer decision until it has had an opportunity to consider a Presentence Investigation report prepared by the United States Probation Office. The parties agree, pursuant to Rule 11(e)(4) of the Federal Rules of Criminal Procedure that if the Court rejects this agreement, Defendant will be afforded an opportunity to withdraw its guilty plea and proceed to

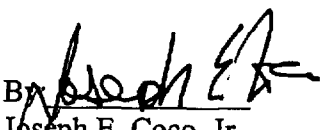
trial.

8. CLAIMS BY INDIVIDUAL DEFENDANTS: Individual defendants in United States v. Koch Industries Inc., et al, Crim No. C-00-325, have relinquished any claim under 18 U.S.C. 3006A.

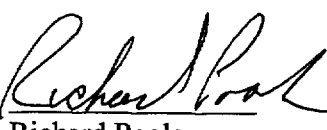
9. ENTIRE AGREEMENT: The United States and KPGLP agree that this Memorandum of Plea Agreement constitutes the entire agreement between them and supersedes any prior agreements. No modification, amendment or waiver of this agreement shall be binding unless made in writing and signed by both parties.


Dated this 9th day of April, 2001.

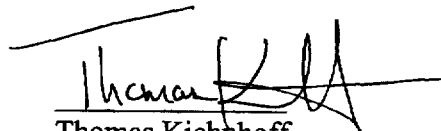
KOCH PETROLEUM GROUP, L.P.

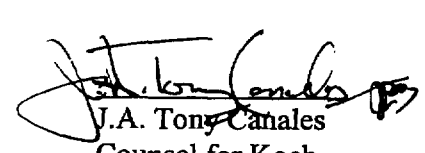

Joseph E. Coco, Jr.
Vice President,
Manufacturing Manager
Koch Petroleum Group, L.P.

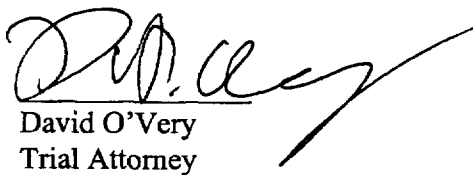
JOHN C. CRUDEN
Acting Assistant Attorney General
Environment and Natural
Resources Division

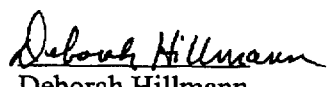

Richard Poole
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Environmental Crimes Section
United States Department of Justice


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Counsel for Koch
Petroleum Group, L.P.


Thomas Kiehnhoff
Special Assistant U.S. Attorney
Southern District of Texas


J.A. Tony Canales
Counsel for Koch
Petroleum Group, L.P.


David O'Very
Trial Attorney
Environmental Crimes Section


Deborah Hillmann
Trial Attorney
Environmental Crimes Section

54

JUDGE PRESIDING: JANIS GRAHAM JACK
CASE MANAGER: Myra Orta Alfano
COURT RECORDER: Velma Gano
LAW CLERK: Chris Jenkins
U. S. P. O. : _____
U. S. P. T. : _____
U. S. MARSHAL: C50 BETTY EMBESON / LONNIE LOZANO
INTERPRETER: _____

United States District Court
Southern District of Texas
APR - 9 2001
MICHAEL N. MILBY
CLERK

DATE: April 9, 2001 OPEN: 11:49 AM ADJOURN: 12:10 pm
TAPE: # 1

CRIMINAL ACTION NUMBER: C-00-325 (1)-(6)

UNITED STATES OF AMERICA

COUNSEL: Richard Poole / David O'Very
Tom Kiehnhoff

VS.
Koch Industries, Inc. / Koch Petroleum Group, L.P.
David L. Lamp
Vincent A. Mietlicki
John C. Wadsworth / James W. Weathers

COUNSEL: Reid Weingarten / Jan Barrett/ N. Hardy
Dick DeGuerin / James Blackburn, Jr.
David Krakoff / Robert Brager / ~~Hana Sultan~~
Michael Ramsey / Henry Schuelke, III/ John Kern

(☒) EPTC:

Case called. Appearances are made. Discussion of the
agreed plea agreement, re: Koch Petrol. Group. Court accepts
the agreement. Deft #2 to be re-arraigned.

TRUE COPY I CERTIFY
ATTEST: 9-5-01
MICHAEL N. MILBY, Clerk of Court
By Honna Terrell
Deputy Clerk

Adjuin

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**SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION**

United States District Court
Southern District of Texas
FILED

APR - 9 2001

UNITED STATES OF AMERICA)

v.)

KOCH PETROLEUM GROUP, L.P.)

MICHAEL N. MILBY

CLERK

CRIM. NO. C-00-325(S)

Hon. Janis Graham Jack

INFORMATION

Count One

From on or about January 7, 1995, through on or about April 7, 1995, at Corpus Christi, Texas, in the Southern District of Texas, defendant KOCH PETROLEUM GROUP, L.P., did knowingly and willfully falsify, conceal and cover up by a trick, scheme and device, material facts in a matter within the jurisdiction of the Texas Natural Resources Conservation Commission and the United States Environmental Protection Agency, to wit, the fact that a control device, the flameless thermal oxidizer known as the Thermatrix, had been disconnected from the Edens separator, a source of benzene vapors, and the fact that defendant had failed to measure the level of benzene entering the aeration basin at the West Plant.

All in violation of Title 18 U.S.C. Section 1001.

JOHN C. CRUDEN
Acting Assistant Attorney General
Environment and Natural
Resources Division




RICHARD POOLE
D.C. Bar No. 295360
Senior Trial Attorney
Environmental Crimes Section
United States Department of Justice

TRUE COPY I CERTIFY

ATTEST: 9-5-01

MICHAEL N. MILBY, Clerk of Court

By 
Deputy Clerk

396

56

AO 455 (Rev. 5/85) Waiver of Indictment

United States District Court

United States District Court
Southern District of Texas

FILED

APR - 9 2001

DISTRICT OF

MICHAEL N. MILBY
CLERK

UNITED STATES OF AMERICA

v.

WAIVER OF INDICTMENT

Roch Petroleum Group, L.P.

CASE NUMBER: *Crim No 000-325(S)(S)*

I, *Joseph E Cocoy* on behalf of *KPGLP*, the above named defendant, who is accused of

being advised of the nature of the charge(s), the proposed information, and of my rights, hereby waive in open court on
4/9/01 Date prosecution by indictment and consent that the proceeding may be by information
rather than by indictment.

Joseph E Cocoy
Defendant

John E Barrett
Counsel for Defendant

Before

Joseph E Cocoy
Judicial Officer

TRUE COPY I CERTIFY
ATTEST: *9-5-01*

MICHAEL N. MILBY, Clerk of Court

By *Donna Terrell*
Deputy Clerk

395

57

HONORABLE JANIS G. IAM JACK, PresidingUnited States District Court
Southern District of TexasCASE MANAGER: Myra Orta AlfanoERO: Velma Gano

USPT: _____

USPO: B. Cazalas ~~XXXXXX~~

INTERPRETER: _____

~~XXXXXX~~ ~~XXXXXX~~USM: Lonnie Lozano / Betty Emerson~~XXXXXX~~ ~~XXXXXX~~

APR - 9 2001

MICHAEL N. MILBY

A.M. 1 P.M. 12:10 / 12:45DATE: April 9, 2001 CLERKTAPE: # 1CR. C-00-325 S S DEFT. 02

UNITED STATES OF AMERICA

VS.

Koch Petroleum Group, LPAUSA: DAVID POOLE / TOM KIENHOFF / DAVID O'LEARY
~~Robert Galvan / Elise Salinas / Terri Beth Phillips / Nazim~~Jan Barrett / Tony Canales

***** RE-ARRAIGNMENT *****

() ORDBWI Defendant failed to appear, bench warrant to issue. (LFUG)

(✓) WVINDIF Waiver of indictment filed.

(✓) PLG Defendant enters a plea of GUILTY to Criminal Information, c.t. 1.

() PLNG Guilty plea refused, NOT GUILTY plea entered.

() FREE TEXT Arraignment as to count(s) _____ deferred.

(✓) FREE TEXT PLEA BARGAIN (✓) WRITTEN PLEA AGREEMENT FILED. (4101(C))

() If the Defendant maintains a plea of guilty to count(s)

through sentencing, the Government agrees to recommend:

() TRDATS Trial date set for _____ at _____

() ORDPSI PSI is Ordered.

() WVPSI PSI is Waived.

() SENS Sentencing set for Instant at _____

(✓) BAILC Bond is continued. () Gov't objects () Gov't does not object

() ORDBNDRVK Bond is revoked.

() ORDBNDFRFT Bond is forfeited.

() ORDBNDPR \$ _____ PR bond is set.

() ORDBND10 \$ _____ w/10% deposit bond set.

() ORDBNDSUR \$ _____ Cash / Surety bond set.

() FREE TEXT Defendant is REMANDED to the custody of the U. S. Marshal.

() OTHER

PROCEEDINGS: Parties present. Defendant sworn in. Court accepts the
waiver of indictment. All pending motions are moot.
Max: 5 yrs Prob. / fine \$400.00 sp. asst. / crim. lnc. \$10 million

TRUE COPY I CERTIFY

ATTEST: 9-5-01

MICHAEL N. MILBY, Clerk of Court

By Donna Terrell
Deputy Clerk

398

58

Southern District of Texas
FILEDHONORABLE JANIS AHAM JACK, PresidingCASE MANAGER: Myra Orta AlfanoERO: Velma GanoUSM: LONNIE LOZANO / BETTY EMERSONUSPO: Bill Cazalas

INTERPRETER: _____

USPT: _____

APR - 9 2001

MICHAEL N. MILBY

A.M. _____ / P.M. 12:45 / 12:51 DATE: APRIL 9, 2001 CLERK#
TAPE: 1CR. C-00-325 SS DEFT. 02

UNITED STATES OF AMERICA

{
{
{
{
{
{AUSA: David Poole / Tom Kiehnhoff / David O'Very~~FILED: Ken Sisk / Mark Davis / Mark Davis / Mark Davis~~

VS.

Koch Petrol. Group, LPJane Barrett / Tony Canales

***** SENTENCING *****

() ORDBWI

Defendant failed to appear, bench warrant is to be issued. (LFUG)

(✓) SENI

Sentencing held.

() WDPLG

Defendant withdraws plea of guilty

(✓) SENTENCE:

Ct (s) 1 : 5 yrs Prob Custody of Bureau of Prison

Supervised Release Term (Standard Conditions, #92-36)

Special Conditions:

() Sp. Cond. #1. Defendant is to undergo Drug Surveillance

() Sp. Cond. #2. Defendant is to undergo Drug Treatment

(✓) Sp. Cond. #3. Fine: 10mil () Payable on a schedule set by the Bureau of

Prisons while in custody (✓) Due immediately () Due 30 days from the date

of the judgment () Balance payable on a schedule to be set by the USPO and to

be paid within the first _____ years of S.R.T.

() Sp. Cond. #4. Community Confinement:

() Sp. Cond. #5. Home Detention:

(✓) Sp. Cond. #6. Community Service: \$10 mil (perist/court) hours as directed

() Sp. Cond. #7. Defendant is required to participate in Mental Health Programs as deemed necessary by the USPO

() Sp. Cond. #8. Deportation

(✓) ~~\$5000/\$100.00~~ Special Assessment is imposed on Count (instant)Count (s) INDIV & KII & KPG are dismissed on Government's Motion, shally.

(✓) DCNTGVMOT

Bond is continued. () Govt. objects () Govt. does not object

(✓) BAILC

Bond is revoked.

() ORDBNDRVK

Bond is forfeited.

() ORDBNDRFT

() FREE TEXT

Defendant is REMANDED to the custody of the U. S. Marshal.

() FREE TEXT

Defendant is to surrender to the U. S. Marshal on _____

() FREE TEXT

Defendant is to surrender to a designated institution.

GUIDELINE RANGE: Def previously served.OTHER PROCEEDINGS: Mtu to dismiss forthcoming.Court orally grants the oral mtu, by deft, to withdraw all exhibits.TEST: 9-5-01

MICHAEL N. MILBY, Clerk of Court

Donna Small
Deputy Clerk

59

**UNITED STATES DISTRICT COURT FOR THE
SOUTHERN DISTRICT OF TEXAS
CORPUS CHRISTI DIVISION**

United States District Court
Southern District of Texas
FILED

APR - 9 2001

MICHAEL N. MILBY
CLERK

UNITED STATES OF AMERICA)

v.)

KOCH INDUSTRIES, INC.)

KOCH PETROLEUM GROUP, L.P.)

DAVID L. LAMP)

VINCENT MIETLICKI)

JOHN C. WADSWORTH)

JAMES W. WEATHERS, JR.)

CRIM. NO. C-00-325(S)

Hon. Janis Graham Jack

**UNITED STATES' MEMORANDUM OF LAW
IN SUPPORT OF ORGANIZATIONAL COMMUNITY SERVICE**

The United States and the Defendants propose a plea agreement that requires, among other things, that Koch Petroleum Group, L.P. ("KPGLP") perform organizational community service by paying 10 million dollars (\$10,000,000) for deposit into an interest-bearing escrow account. In consultation with the United States Environmental Protection Agency ("EPA") and the Texas Natural Resource Conservation Commission ("TNRCC"), KPGLP will then propose community service projects to be used for air or water quality remediation projects in and around the city of Corpus Christi, Texas, using funds distributed from the escrow account. The environmental projects proposed by KPGLP will be subject to the approval of the Court and agreement of the Environmental Crimes Section of the Department of Justice.

The following memorandum sets out the legal authorities in support of the organizational community service provisions of the proposed plea agreement as described to the Court in a telephonic hearing held on April 6, 2001.

TRUE COPY I CERTIFY
ATTEST: 8-5-01
MICHAEL N. MILBY, Clerk of Court
By Norma Tenell
Deputy Clerk

398

I. THE TEN MILLION DOLLAR PAYMENT SHOULD BE DESIGNATED AS ORGANIZATIONAL COMMUNITY SERVICE NOT RESTITUTION

As stated above, the \$10,000,000 payment is designated as community service in the proposed plea agreement. The Sentencing Reform Act (“SRA”) and the Federal Sentencing Guidelines (“Sentencing Guidelines”) authorize organizational community service payments as part of a plea agreement. As a discretionary condition of probation, the SRA authorizes the Court to order a defendant to “work in community service.” 18 U.S.C. § 3563(b)(12). Chapter 8 of the Sentencing Guidelines applies to criminal sentencing for organizations. Section 8B1.3 of the Sentencing Guidelines authorizes the Court to order organization community service as a condition of probation. The introductory commentary to Part B of Chapter 8 states that an order of probation requiring community service “can be used to reduce or eliminate the harm threatened . . . by the offense[.]”

Although the SRA and the Sentencing Guidelines also authorize payments as restitution, any restitution payments must be in accordance with the Victim and Witness Protection Act (“VWPA”). 18 U.S.C. §§ 3563(b)(2); 3556; 3663. In this case, restitution is not authorized and is not appropriate, because the VWPA provides for restitution only in cases of death or bodily injury or “damage to or loss or destruction” of a victim’s property.¹ The VWPA defines a “victim” as “a person directly and proximately harmed” as a result of the offense. 18 U.S.C. §3663(a)(2). See, United States v. Casamento, 887 F.2d. 1141, 1177-78 (2d Cir.), cert. denied, 493 U.S. 1081 (1990).

¹ 18 U.S.C. §§ 3663(b)(1) - (5).

The government may receive restitution payments as a victim when it has directly suffered harm, including monetary loss, from the offense.² The government may also receive payments as restitution when it has spent emergency response or cleanup costs incurred as a result of the environmental violation.³ However, since the government did not suffer harm or incur any losses in this case, other than investigation and prosecution costs which are not recoverable under the VWPA, the government should not receive the \$10,000,000 payment as restitution under the proposed plea agreement.⁴

II. AS A CONDITION OF ITS COMMUNITY SERVICE, IT IS APPROPRIATE FOR KPGLP TO PROPOSE THE ENVIRONMENTAL PROJECTS

As stated above, the plea agreement requires KPGLP, in consultation with the EPA and the TNRCC, to propose the environmental projects subject to approval by the Court and agreement by the Department of Justice. This approach is consistent with the Sentencing Guidelines, because it requires KPGLP to become involved with the projects beyond merely making the payment to the escrow account. The commentary to section 8B1.3 favors community

² See, United States v. Gibbens, 25 F.3d 28, 32-33 (1st Cir. 1994); Ratliff v. United States, 999 F.2d 1023, 1026 (6th Cir. 1993) (collecting cases); United States v. Martin, 128 F.3d 1188, 1190-92 (7th Cir. 1997) (collecting cases); United States v. Ruffen, 780 F.2d 1493, 1496 (9th Cir.), cert. denied, 479 U.S. 963 (1986).

³ See, United States v. West Indies Transport, 127 F.3d 299, 315 (3rd Cir.), cert. denied, 522 U.S. 1052 (1998). In this case, the Third Circuit ordered the defendants to pay restitution based on the Coast Guard's estimates of costs to pay for cleanup of environmental damage caused by the defendant's criminal violations of the CWA.

⁴ See, United States v. Meacham, 27 F.3d 214, 217-218 (6th Cir. 1994), cert. denied, 519 U.S. 1017 (1996) ("[R]estitution may not be awarded under the VWPA for investigation and prosecution costs incurred in the offense of conviction. . . . The fact that a defendant may have entered into an agreement to pay the costs of investigation to the government does not alter this conclusion.").

service where the organization “possesses knowledge, facilities, or skills” that would qualify it to address the violation. The commentary is consistent with a line of cases dealing with violations of the Sherman Act under the old Federal Probation Act, 18 U.S.C. § 3651 (repealed).⁵ In these cases, the court upheld donations to charity as community service, because the defendants did not just “write a check and walk away” but were involved in the charitable activities they helped fund.⁶ As a corporate citizen and member of the Corpus Christi community, KPGLP is in a good position to understand the environmental priorities of the area and should take an active part in the projects.

III. IT IS NOT APPROPRIATE FOR THE GOVERNMENT TO SPEND, USE, OR CONTROL THE FUNDS DESIGNATED AS COMMUNITY SERVICE

As stated above, the United States should not receive the \$10,000,000 payment as restitution, unless the government was a victim and suffered a loss from the defendants’ violations. It is also not appropriate for the government to spend or use the funds designated as community service. The first concern is that government use or control of the community service funds for environmental projects may appear to be an improper infringement on the federal appropriations process and the Miscellaneous Receipts Act (“MRA”) which requires that any money received for the government be deposited into the Crimes Victims Fund of the U.S. Treasury. 31 U.S.C. § 3302(b), 42 U.S.C. § 10601(b).

⁵ See, United States v. Mitsubishi, 677 F.2d 785 (9th Cir. 1982) (1 year loan of executive to community program); United States v. William Anderson, 698 F.2d 911 (8th Cir. 1982) (defendants to work for charity organization); United States v. Posner, 694 F.Supp. 881 (S.D. Fla. 1988) (defendant to develop project to fight homelessness); United States v. Danilow Pastry Co., 563 F.Supp. 1159 (S.D.N.Y. 1983) (donations of baked goods to homeless shelters).

⁶ See, Mitsubishi, 677 F.2d at 788; United States v. Scher Presents, 746 F.2d 959, 963 (3rd Cir. 1984).

Most of the written opinions interpreting the MRA have been issued by the Comptroller General, the head of General Accounting Office ("GAO") of the United States Congress.⁷ Executive Agencies and members of Congress often seek opinions from the Comptroller General on issues related to agency appropriations. The Comptroller has interpreted 31 U.S.C. § 3302(b) as follows: "This statute requires an agency to deposit into the General Fund of the Treasury any funds it receives outside of the agency unless the receipt constitutes an authorized repayment or unless the agency has statutory authority to retain the funds for credit to its own appropriations." Matter of: General Services Administration Contract, B-214091, 64 Comp. Gen. 217, 218-19 (1985). The Comptroller has held that government agencies may not spend funds beyond those which are specifically appropriated, because this amounts to an illegal augmentation of funds beyond those which Congress has authorized.⁸ Similarly, it would not be appropriate for the government to manage or control funds designated as community service. It is a violation of the Anti-Deficiency Act for federal officials who are acting within the scope of their duties to manage or control funds outside of the federal appropriations process. 31 U.S.C. § 1341(a)(1).

IV. THE PLEA AGREEMENT ENSURES THAT KPGLP DOES NOT RECEIVE INAPPROPRIATE PUBLICITY FROM THE PAYMENT

In the telephonic hearing held with this Court on April 6, 2001, the Court expressed concern that KPGLP may gain inappropriately favorable publicity from the environmental projects funded by the community service payment. The terms of the plea agreement ensures

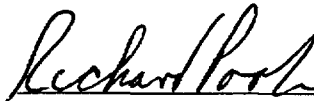
⁷ See generally, Bowsher v. Synar, 478 U.S. 714, 730-31 (1986). Opinions of the Comptroller General are not binding on courts. Delta Chemical Corp. v. West, 33 F.3d 380, 382 (4th Cir. 1994).

⁸ See, Matter of: Federal Emergency Management Agency - Disposition of Monetary Award Under False Claims Act, 1990 WL 268526 (Comp. Gen.), 69 Comp. Gen. 260.

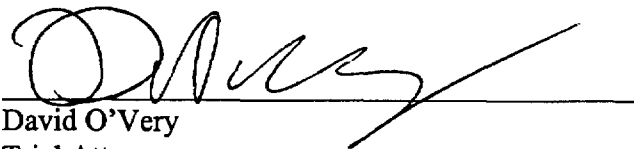
against this result and also ensures that KPGLP not gain any favorable tax advantages from such payment.⁹ Section 2B1 of the proposed plea agreement states that, "Defendant agrees that it will not seek any reduction in its tax obligations as a result of its payment, and that it will not characterize, publicize, or refer to the payment as anything other than a community service payment made as a condition of probation incidental to a criminal conviction."

Respectfully Submitted,

JOHN C. CRUDEN
Acting Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice
Washington, D.C.



RICHARD POOLE
Attorney In Charge
Senior Trial Attorney
DC Bar No. 295360
Environmental Crimes Section
Environment and Natural Resources Division
U. S. Department of Justice
P.O. Box 23985
Washington, D.C. 20026
(202) 514-0838



David O'Very
Trial Attorney
Environmental Crimes Section

⁹ 26 U.S.C. § 162(f). See, True v. United States, 894 F.2d 1197, 1204 (10th Cir. 1990); United States v. Allied Signal, 40 Env't Rep. Case 1660 (3rd Cir. 1995).

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS

VOLUME 4 OF 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

**P.D. HAMILTON, Individually and as
Trustee of the Prentice Dell Hamilton and
Florine Hamilton Family Trust**

VS.

CIVIL ACTION NO. 9:01CV132

**KOCH INDUSTRIES, INC., Individually
and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
GS PIPELINE COMPANY, L.L.C.,
ENTERGY-KOCH, L.P., and
EKLP, L.L.C.**

**APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS**

VOLUME 4 OF 5

TAB NO.

64. Certified Copy of the State of Minnesota's Complaint filed in *United States v. Koch Petroleum Group, L.P.*, Civil Action No. 00-CV-2756, United States District Court for the District of Minnesota
65. Certified Copy of Consent Decree filed in *United States v. Koch Petroleum Group, L.P.*, Civil Action No. 00-CV-2756, United States District Court for the District of Minnesota
66. Certified Copies of Jury Verdict Form No. 1 and Jury Verdict Form No. 2 filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
67. Certified Copy of Order Denying Defendants' Motion for Judgment as a Matter of Law filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
68. Certified Copy of Second Amended Complaint for Violations of the False Claims Act filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
69. Certified Copy of Joint Application to Strike the Penalty Phase Proceeding filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma
70. Certified Copy of Order filed in *United States of America, ex rel., William I. Koch and William A. Presley v. Koch Industries, Inc., et al.*, Case No. 91-CV-763-K, United States District Court for the Northern District of Oklahoma

60

A true copy in _____ sheet (s)
of the record in my custody
CERTIFIED, 9-7-01
Richard D. Sletten, Clerk
BY: Conna Deputy Clerk

UNITED STATES DISTRICT COURT
DISTRICT OF MINNESOTA

UNITED STATES OF AMERICA,)
)
Plaintiff,)
)
v.)
)
KOCH PETROLEUM GROUP, L.P.,)
)
Defendant.)

~~99-MG-568 (ATB)~~
INFORMATION CR 99-270 ADM

(33 U.S.C. § 1321(b)(3))
(33 U.S.C. § 1318(a))
(33 U.S.C. § 1319(c)(1))

THE UNITED STATES ATTORNEY CHARGES THAT:

COUNT I
(Oil Pollution Act Violation)

From in or about December, 1992 through in or about August, 1999, in the State and District of Minnesota, the defendant,

KOCH PETROLEUM GROUP, L.P.,

did negligently discharge, from its refinery in Rosemount, Minnesota into waters of the United State and adjoining shorelines, namely, the backwaters and wetlands of the Mississippi River, oil in such quantities as may be harmful, all in violation of Title 33, United States Code, Sections 1321(b)(3) and 1319(c)(1).

COUNT II
(Clean Water Act Violation)

From in or about November 1996 through in or about March 1997, in the State and District of Minnesota, the defendant,

KOCH PETROLEUM GROUP, L.P.,

did negligently render inaccurate a monitoring method required to be maintained under the Clean Water Act, that is, it discharged wastewater onto the ground on multiple occasions and it increased the weekend flow of the wastewater discharge to the Mississippi

(1)

FILED **SEP 28 1999**
FRANCIS E. DOSAL, CLERK
JUDGES: ENTD
DEPUTY CLERK [Signature]

River, when no sampling was required, thereby negligently rendering inaccurate the monthly averages of ammonia that were required to be reported on monthly discharge monitoring reports, all in violation of Title 33, United States Code, Sections 1318(a) and 1319(c)(1).

Dated:

September 28, 1999

[Signature]
B. TODD JONES
United States Attorney

[Signature]
BY: R. J. ZAYED and
MARGARET BURNS MAGILL
Assistant U.S. Attorneys

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A true copy in 11 sheet (s)
of the record in my custody
CERTIFIED 9/19/01
BY: Richard D. Sletten, Clerk
Deputy Clerk

UNITED STATES DISTRICT COURT
DISTRICT OF MINNESOTA
Criminal No. 99-MG-568 (ADB)

CR 99-270 ADM

UNITED STATES OF AMERICA,)
)
Plaintiff,)
)
v.)
)
KOCH PETROLEUM GROUP, L.P.)
)
Defendant.)

**PLEA AGREEMENT AND
SENTENCING STIPULATIONS**

The parties to the above-captioned case, the United States of America and the defendant, Koch Petroleum Group, L.P., by and through their undersigned attorneys, agree to resolve this case on the terms and conditions set forth in this Agreement. This Plea Agreement is binding only on the defendant and the United States Attorney's Office for the District of Minnesota.

BACKGROUND

1. The United States and defendant agree that, had the United States tried this matter against defendant, the United States would have offered evidence to prove the factual assertions set forth below. Defendant admits that it committed the offenses charged in the counts to which it is pleading guilty, and that the United States could prove each of the essential elements of those offenses beyond a reasonable doubt. Defendant agrees that the Court may rely on the following factual assertions in determining, under Rule 11 of the Federal Rules of Criminal Procedure, that there is a factual basis for the guilty pleas as provided in this agreement.

(2)

SEP 28 1999
FILED
FRANCIS E. DOSAL, CLERK
JUDGE: ENTD
DEPUTY CLERK: [Signature]

A. Historical and Permit Background

(1) Defendant is a Delaware Limited Partnership that owns and operates a oil refinery located in Rosemount, Minnesota. Defendant employs approximately 800 people at its Rosemount facility.

(2) Defendant refines crude oil into various petroleum products. As part of its refining process, defendant generates wastes, including hazardous wastes, oily process wastewater and other miscellaneous waste streams. After treatment, the wastewater is discharged through a designated Outfall into the Mississippi River.

(3) The Outfall is a point source as defined in section 502(14) of the Clean Water Act, 33 U.S.C. § 1362(14). The discharged wastewater stream contains a variety of substances that are pollutants within the meaning of Section 502(6) of the Clean Water Act, 33 U.S.C. § 1362(6). The Mississippi River is a "navigable water," as defined by Section 502(7) of the Clean Water Act, 33 U.S.C. § 1362(7) and 40 C.F.R. § 122.2

(4) On December 28, 1983, the Minnesota Pollution Control Agency ("MPCA"), under the authority of the United States Environmental Protection Agency ("EPA") and the Clean water Act, 33 U.S.C. § 1342(b), issued National Pollutant Discharge Elimination System ("NPDES") Permit No. MN0000418. The MPCA reissued the 1983 NPDES permit on December 28, 1989 and again on May 10, 1994. The 1994 NPDES permit limited the amount of pollutants, including ammonia, that defendant could discharge into the Mississippi River.

(5) The 1994 NPDES Permit also required defendant to monitor, sample and test, on a regular basis, the wastewater being discharged into the Mississippi River to ensure compliance with the permit limits. The monitoring and testing were required to be representative of the volume and nature of the wastewater discharge. However, the permit allowed defendant to test its wastewater only five days per week. The permit further required defendant to report the results of this regular monitoring and testing to the MPCA on a monthly basis using a Discharge Monitoring Report ("DMR").

B. Oil Pollution Act Violation

(1) On August 20, 1997, aviation fuel was discovered to be seeping from a spring into a wetland and an adjoining navigable water in the vicinity of Spring Lake next to the Mississippi River. The aviation fuel did not reach the Mississippi River itself. The wetland and the adjoining navigable water are "waters of the United States" as they are directly connected to the Mississippi River and are subject to the ebb and flow of the Mississippi River's tide.

(2) The seepage of aviation fuel was determined to be from a leak from Tank 16 at the Rosemount Refinery. By the time the seepage was discovered, the fuel had contaminated portions of the wetland. It also had produced a number of visible oil sheens on the surface of the adjoining navigable water.

(3) To prevent the fuel from reaching the Mississippi River, defendant placed booms across the surface of the adjoining

navigable water to collect the fuel. It also dug a trench which extended into the wetland to collect and pump the fuel as it seeped into the wetland. In digging the trench and setting up a recovery system, defendant destroyed a portion of the surrounding ecosystem and wild life habitat.

(4) Defendant's actions in allowing the fuel to reach the wetland and adjoining navigable water were negligent. As early as February 1992, defendant had reason to believe that Tank 16 had holes in its floor. By September 1992, defendant through inventory control records had reason to believe that Tank 16 had lost a significant quantity of aviation fuel. Defendant conducted internal tests of Tank 16, but failed to notify the MPCA about the leak or its size.

(5) In early December 1992, defendant emptied Tank 16 and took it off line. Defendant then discovered that there were 34 holes in the bottom of the tank. On December 31, 1992, defendant notified the MPCA about the leak but stated that the amount of the leak was unknown.

(6) In early 1993, defendant had reason to believe that Tank 16 had lost between 200,000 and 600,000 gallons of aviation fuel. Defendant hired an engineering consulting firm to assist it in tracking the leak and developing a plan to recover the fuel and remediate the contaminated soil and groundwater. Although defendant was aware that the fuel would eventually reach the Mississippi River if it was not recovered in time, defendant did not have a comprehensive plan developed to recover the fuel until

June 1997. In the interim, defendant used various ad-hoc methods and equipment in an effort to recover the fuel.

(7) Defendant failed to recover the fuel as rapidly and thoroughly as possible and failed to take other reasonable steps to avoid, minimize or abate the pollution of the waters of the United States. Defendant's failure was negligent and resulted in the discharge of harmful quantities of oil into waters of the United States.

C. Clean Water Act Violation

(1) Sometime in the summer of 1996 and continuing through March 1997, defendant experienced problems with high levels of ammonia in its wastewater. Because ammonia was one of the pollutants regulated by the NPDES permit, the discharge of ammonia above certain limits was prohibited. Accordingly, defendant stacked the high-ammonia wastewater in its storm water ponds and its fire hydrant lagoons.

(2) Once the ponds and lagoons had reached their capacity, defendant would discharge the wastewater onto the ground using its fire hydrants. Defendant discharged wastewater onto the ground on multiple occasions between November 1996 and March 1997, dumping millions of gallons of wastewater onto the ground.

(3) In February 1997, defendant experienced significant problems with high levels of ammonia in its wastewater. Defendant stacked its ponds and lagoons and dumped over a million gallons of wastewater onto the ground. Further, defendant increased the flow

of the wastewater discharged into the Mississippi River on the weekends. Since it was not required to test the wastewater on the weekends, defendant was able to circumvent the weekly monitoring and reporting requirements. By increasing the flow on the weekends and not including it in its calculation of the monthly average, defendant negligently rendered inaccurate a monitoring method required under the permit and the Clean water Act.

PLEA AGREEMENT

2. The defendant agrees to enter a plea of guilty to Count I and Count II of an Information. Count I charges the defendant with negligently discharging a harmful quantity of oil into the navigable waters of the United States, in violation of the Oil Pollution Control Act of 1990, 33 U.S.C. §§ 1321(b)(3), 1319(c)(1)(A). Count II charges defendant with a negligent violation of the Clean Water Act, 33 U.S.C. § 1318(a), 1319 (c)(1)(A). The defendant further agrees to waive its right to Indictment by a United States grand jury and agrees to be charged by Information.

3. The defendant understands that each of Count I and Count II carries a maximum potential penalty of:

A. a fine not more than the greatest of:

(1) up to \$200,000,

(2) twice the amount of pecuniary loss to a person other than the defendant,

- (3) twice the amount of pecuniary gain to any person, or
- (4) not more than \$25,000 per day of violation.

- B. restitution;
- C. a mandatory special assessment of at least \$125;
- D. a term of probation not less than one year nor more than five years.

4. The parties agree that the Sentencing Guidelines, relating to the Sentencing of Organizations (Chapter 8), are applicable to this criminal offense, except for the imposition of a fine.

SENTENCING STIPULATIONS

5. The United States and defendant agree, pursuant to Fed.R.Crim.P. 11(e)(1)(B) to a specific sentence as set out below. The parties understand and agree that the Court is not bound to follow the recommendations of the parties in the Plea Agreement. However, should the Court not follow the agreement reached by the parties, the parties will have the right to withdraw from the Plea Agreement.

A. Fine

Defendant will be liable for a federal criminal fine in the amount of \$6,000,000 to be paid at the time of sentencing. No amount of the fine shall reduce the Defendant's civil liability to any person or entity, including any federal, state or local government agency.

B. Probation

Defendant will be placed on probation for a period of three (3) years, a condition of which is that defendant will undertake the measures set forth below.

(1) Community Service

Pursuant to Sentencing Guideline Section 8B1.3, and in furtherance of remediation of the Spring Lake Park Reserve, defendant agrees to pay \$2,000,000 to Dakota County, Minnesota for implementation of the Schaars Bluff Concept Plan, dated September 2, 1998. Defendant agrees to make full payment at the time of sentencing and further agrees that it will not claim any federal, state or local tax credit for any expense related to the fulfillment of this condition of probation.

(2) Environmental Compliance Program

Defendant acknowledges that the federal sentencing guidelines require the Court to determine whether the defendant has an effective program to detect and prevent violations of the law and permits the Court to order the defendant to develop and implement such a program if its current program is found to be inadequate. Sentencing Guidelines, Sections 8A1.2 and 8D1.4(c). To that end, defendant shall submit all evidence of its existing program to the Probation Office and the United States at least 30 days prior to sentencing. Defendant will comply with the recommendations and requirements of the Court with respect to

ensuring that any compliance program will adequately prevent or detect any future violations of law.

(3) Environmental Audit

Defendant acknowledges that the EPA is currently conducting a comprehensive environmental audit of Koch's Rosemount Refinery and agrees to cooperate with the EPA during the audit process. The parties agree that an additional environmental audit as a condition of probation is not necessary.

(4) Responsible Officers

The defendant shall designate responsible corporate officers, including a corporate officer at Koch headquarters and the plant manager at the Rosemount Refinery, to be personally responsible for implementing and overseeing the fulfillment of the conditions of probation.

(5) Lawful Conduct

Defendant agrees not to violate any state, federal or local law during the period of probation. Further, nothing in this Agreement shall limit defendant's criminal or civil liability for

any environmental deficiency or violation identified during the period of probation.

(6) Stipulated Penalty

If defendant fails to comply with the conditions of probation, the defendant will be required to pay at least an additional \$100,000 fine, in addition to whatever other penalties may be imposed by the Court.

6. Defendant acknowledges that its convictions pursuant to this plea agreement will trigger the debarment from government contracts and grants provisions of 33 U.S.C. 1368 and 40 C.F.R. Part 33. Defendant agrees to comply with the provisions of any settlement agreement reached with the EPA Suspension and Debarment Program related to this Plea Agreement.

7. Defendant agrees to pay the \$125 special assessment per Count at or before the time of sentencing.

8. The United States agrees that if the defendant is sentenced under the terms of this Agreement there will be no further federal criminal prosecution in the District of Minnesota of the defendant,

Koch Petroleum Group, L.P., or its current or former employees, managers, directors, officers or affiliates for environmental violations disclosed by the May 1997 MPCA inspection of the Rosemount Refinery and known to the District of Minnesota, the EPA and the Federal Bureau of Investigation at the time of this Plea Agreement.

Dated:

September 27, 1999

ROBERT M. SMALL
Acting United States Attorney

By:

R. J. Zayed
R. J. ZAYED
Assistant U.S. Attorney

Dated:

9/27/99

Margaret Burns Magill
MARGARET BURNS MAGILL
Assistant U.S. Attorney

Dated:

9/27/99

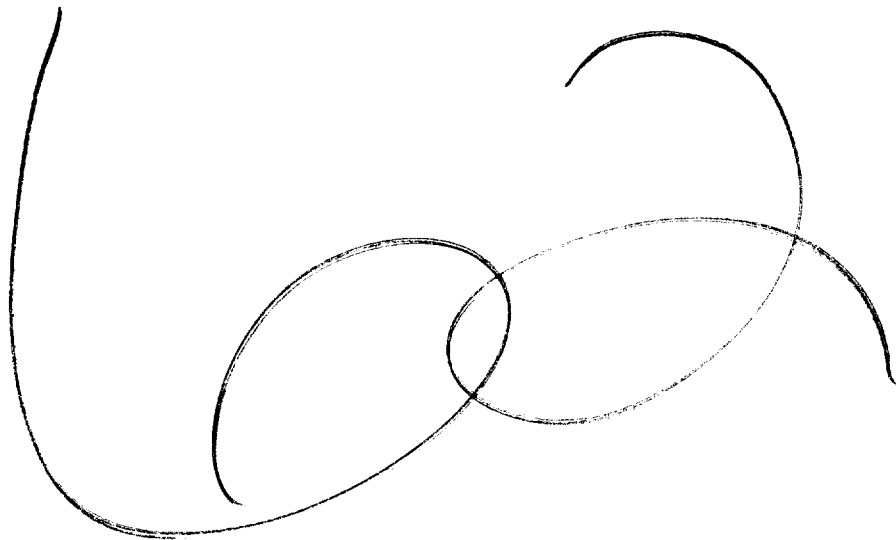
Andrew Luger
ANDREW LUGER
Counsel for Defendant

Dated:

Koch Petroleum Group, L.P.
Defendant

By:

James L. Mahoney
KPG GP, Inc. its General Partner
JAMES L. MAHONEY
Senior Vice President

A handwritten signature or scribble consisting of several overlapping loops and curves, rendered in black ink on a white background.

United States District Court

District of Minnesota

UNITED STATES OF AMERICA
v.
KOCH PETROLEUM GROUP, L.P.

JUDGMENT IN A CRIMINAL CASE

(For Offenses Committed On or After November 1, 1987)

Case Number: 99-270

Andrew Lugar

Defendant's Attorney

A true copy in 4 sheet(s)

of the record in my custody,

CERTIFIED, 9/7 2001BY: Richard D. Sletten, ClerkDeputy Clerk Thomas J. O'Connell

THE DEFENDANT:

- ☒ pleaded guilty to count(s): 1 and 2 of the Information.
☐ pleaded nolo contendere to count(s) ___ which was accepted by the court.
☐ was found guilty on count(s) ___ after a plea of not guilty.
Accordingly, the defendant is adjudged guilty of such count(s), which involve the following offenses:

Title & Section	Nature of Offense	Date Offense Concluded	Count Number(s)
33 USC 1321(b)(3) and 1319(c)(1)(A)	Negligent Discharge of a Harmful Quantity of Oil into the Navigable Waters of the United States	12/92-8/99	1
33 USC 1318(a) and and 1319(c)(1)	Negligent Violation of the Clean Water Act	11/96-3/97	2

The defendant is sentenced as provided in pages 2 through 4 of this judgment. The sentence is imposed pursuant to the Sentencing Reform Act of 1984.

- ☐ The defendant has been found not guilty on count(s) ___ and is discharged as to such count(s).
☐ Count(s) ___ (is){are} dismissed on the motion of the United States.

Special Assessment Amount \$ 250 in full and immediately.

IT IS FURTHER ORDERED that the defendant shall notify the United States Attorney for this district within 30 days of any change of name, residence, or mailing address until all fines, restitution, costs, and special assessments imposed by this judgment are fully paid.

Defendant's Soc. Sec. No.:

Defendant's Date of Birth:

Defendant's USM No.:

Defendant's Residence Address:

Defendant's Mailing Address:

Filed MAR 03 2000

Francis E. Dosal, Clerk

Judgment Entd

Deputy Clerk [Signature]

(dist. cl.)

A true copy in 4 sheet(s)
of the record in my custody.
Certified _____, 19____
by _____
Deputy Clerk

3/1/00

Date of Imposition of Judgment

Signature of Judicial Officer

ANN D. MONTGOMERY, United States District Judge

Name & Title of Judicial Officer

March 3, 2000
Date

(11)

CASE NUMBER: 99-270
DEFENDANT: KOCH PETROLEUM GROUP, L.P.

PROBATION

The defendant is hereby placed on probation for a term of 3 years

The defendant shall not commit another federal, state, or local crime.

SPECIAL CONDITIONS OF PROBATION

1. The defendant shall make payment to Dakota County, Minnesota, in the amount of \$2,000,000.00 for remediation of the Spring Lake Park Reserve. Payment is due and payable immediately, and shall be paid to the Clerk of Court for disbursement.
2. The organization shall not commit any crimes, federal, state or local. Nothing in the sentence shall limit defendant's criminal or civil liability, or cause any deficiency or void during the three year period of probation.
3. The organization shall submit to a reasonable number of regular or unannounced examinations of its books, records, and facilities by the probation office or experts engaged by the Court; and interrogation of knowledgeable individuals within the organization. Compensation to and costs of any experts engaged by the Court shall be paid by the defendant organization. This condition is intended to adequately prevent or detect any future violations.
4. The organization shall comply with the recommendations and requirements of the Court with respect to ensuring that any compliance program will adequately prevent or detect any further violations of law.
5. The organization shall designate responsible corporate officers, including a corporate officer at Koch headquarters and the plant manager at the Rosemount refinery, to be personally responsible for implementing and overseeing the fulfillment of the conditions of probation.
6. The defendant organization shall fully cooperate with the EPA and the MPCA during current and future comprehensive environmental audits and/or investigations.
7. The organization agrees to comply with the provisions of the settlement agreement which has been reached with the EPA Suspension and Debarment Program.
8. If defendant fails to comply with the conditions of probation, the defendant will be required to pay at least an additional \$100,000 fine, in addition to whatever other penalties may be imposed by the Court.

CASE NUMBER: 99-270
 DEFENDANT: KOCH PETROLEUM GROUP, L.P.

CRIMINAL MONETARY PENALTIES

The defendant shall pay the following total criminal monetary penalties in accordance with the Schedule of Payments set forth on Sheet 5, Part B.

	<u>Fine</u>	<u>Restitution</u>
Totals:	\$ 6,000,000.00	\$

[] If applicable, restitution amount ordered pursuant to plea agreement \$ ____

FINE

The above fine includes costs of incarceration and/or supervision in the amount of \$ ____.

The defendant shall pay interest on any fine of more than \$2500, unless the fine is paid in full before the fifteenth day after the date of judgment, pursuant to 18 U.S.C. §3612(f). All of the payment options on Sheet 5, Part B may be subject to penalties for default and delinquency pursuant to 18 U.S.C. §3612(g).

[] The court determined that the defendant does not have the ability to pay interest and it is ordered that:

[] The interest requirement is waived.

[] The interest requirement is modified as follows:

RESTITUTION

[] The determination of restitution is deferred in a case brought under Chapters 109A, 100, 110A and 113A of Title 18 for offenses committed on or after 09/13/1994, until up to 60 days. An amended Judgment in a Criminal Case will be entered after such determination.

[] The court modifies or waives interest on restitution as follows:

[] The defendant shall make restitution to the following payees in the amounts listed below.

If the defendant makes a partial payment, each payee shall receive an approximately proportional payment unless specified otherwise in the priority order of percentage payment column below.

<u>Name of Payee</u>	<u>**Total Amount of Loss</u>	<u>Amount of Restitution Ordered</u>	<u>Priority Order or % of Pymnt</u>
	<u>TOTALS:</u>	\$ ____	\$ ____

** Findings for the total amount of losses are required under Chapters 109A, 110, 110A, and 113A of Title 18 for offenses committed on or after September 13, 1994.

SCHEDULE OF PAYMENTS

Payments shall be applied in the following order: (1) assessment; (2) restitution; (3) fine principal; (4) cost of prosecution; (5) interest; (6) penalties.

Payment of the total fine and other criminal monetary penalties shall be due as follows:

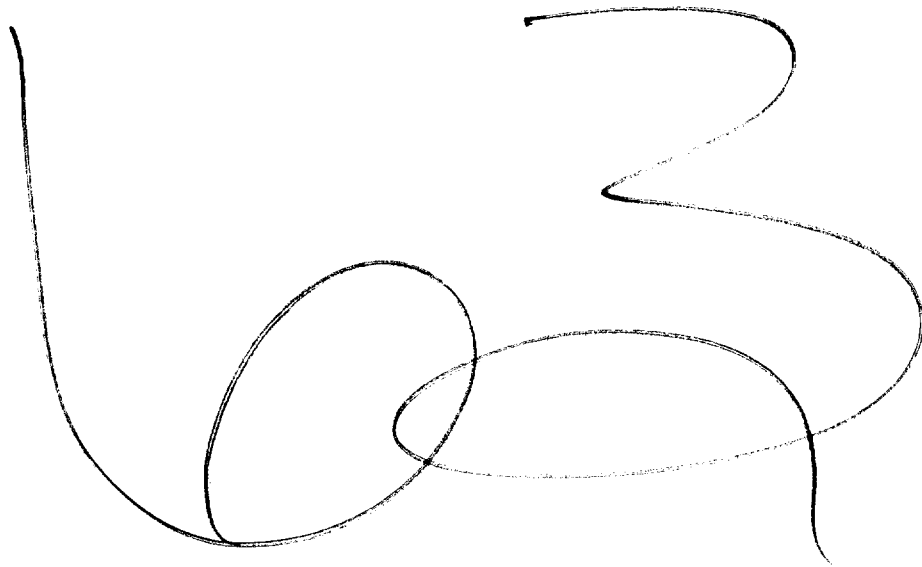
- A ☒ in full immediately; or
- B ☐ \$ _ immediately, balance due (in accordance with C, D, or E); or
- C ☐ not later than _ ; or
- D ☐ in installments to commence _ day(s) after the date of this judgment. In the event the entire amount of criminal monetary penalties imposed is not paid prior to the commencement of supervision, the U.S. probation officer shall pursue collection of the amount due, and shall request the court to establish a payment schedule if appropriate; or
- E ☐ in _ (e.g. equal, weekly, monthly, quarterly) installments of \$ _ over a period of _ year(s) to commence _ day(s) after the date of this judgment.

Special instructions regarding the payment of criminal monetary penalties:

Because the fine arises out of the statutory citations in 33 U.S.C. §§1319(a),(b), and (c) and §1321 the check should be made payable to the U.S. Coast Guard, ART, for disbursement by the U.S. District Court. The case number and defendant name should accompany payment.

☐ The defendant shall pay the cost of prosecution.

☐ The defendant shall forfeit the defendant's interest in the following property to the United States:

A handwritten mark, possibly a signature or a large scribble, consisting of several overlapping loops and curves. It starts with a vertical line on the left, curves into a large loop, then another loop, and ends with a long, sweeping curve on the right side.

ORIGINAL

UNITED STATES DISTRICT COURT
DISTRICT OF MINNESOTA

UNITED STATES OF AMERICA,

Plaintiff,

v.

KOCH PETROLEUM GROUP, L.P.

Defendant.

A true copy in 34 sheet(s)
of the record in my custody.
CERTIFIED 9-7-01 20 01
By: Richard D. Sletten, Clerk
Deputy Clerk

CIVIL ACTION NO.

00-2756
PAM/SRW

COMPLAINT

The United States of America, by the authority of the Attorney General of the United States and through the undersigned attorneys, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), alleges:

NATURE OF ACTION

1. This is a civil action brought against Koch Petroleum Group, L.P. ("Koch" or "Defendant") pursuant to Section 113(b) of the Clean Air Act ("CAA" or the Act), 42 U.S.C. § 7413(b), for alleged environmental violations at its three petroleum refineries: Pine Bend, Minnesota, and Corpus Christi West and East. All three Koch refineries have been and are in violation of EPA's regulations implementing the following Clean Air Act statutory and regulatory requirements applicable

1

FILED DEC 22 2000

FRANCIS E. DOSAL CLERK

JUDGMENT ENTD

DEPUTY CLERK

to the petroleum refining industry: New Source Performance Standards ("NSPS"), 40 C.F.R. Part 60, Subpart J; Leak Detection and Repair ("LDAR"), 40 C.F.R. Parts 60 and 63; National Emission Standards for Hazardous Air Pollutants ("NESHAP") for Benzene, 40 C.F.R. Part 61; and the Minnesota and Texas state implementation plans ("SIPs") which incorporate and/or implement the above-listed federal regulations. Koch is also in violation of Part C of Title I of the Act, 42 U.S.C. § 7470-7492, the Prevention of Significant Deterioration (PSD) for modifications at its Pine Bend refinery.

2. In addition the United States alleges that Koch has violated and is in violation of the following federal environmental statutes and their implementing regulations at its Pine Bend, Minnesota refinery: the Resource Conservation and Recovery Act, ("RCRA"), 42 U.S.C. § 6901 et seq., the Clean Water Act ("CWA"), 33 U.S.C. § 1321(b)(3) and (j), the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), 42 U.S.C. § 9603(a); and the Emergency Planning and Community Right to Know Act ("EPCRA"), 42 U.S.C. § 11004(a).

3. The United States seeks an injunction ordering Defendant to comply with the above statutes and the laws and

regulations promulgated thereunder, and civil penalties for Defendant's past and ongoing violations.

JURISDICTION AND VENUE

4. This Court has jurisdiction over the subject matter of this action pursuant to 28 U.S.C. §§ 1331, 1345 and 1355; Section 113(b) of the CAA, 42 U.S.C. § 7413(b); Section 3008(a) of RCRA, 42 U.S.C. § 6928(a); Section 109(c) of the Clean Water Act, 33 U.S.C. § 1319(b); Sections 109(c) and 113(b) of CERCLA, 42 U.S.C. §§ 9609(c) and 9613(b); and Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3).

5. Venue is proper in this District pursuant to 28 U.S.C. §§ 1391(c); Section 113(b) of the CAA, 42 U.S.C. § 7413(b); Section 3008(a) of RCRA, 42 U.S.C. § 6928(a); and Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3), because certain of the violations alleged herein occurred at the Pine Bend Refinery, which is located in this district.

NOTICE TO STATE

6. Notice of the commencement of this action has been given to the States of Minnesota and Texas, as required under Section 113(b) of the CAA, 42 U.S.C. § 7413(b), and to the State of Minnesota, as required under Section 3008(a)(2) of RCRA, 42 U.S.C. § 6928(a)(2).

DEFENDANT

7. Defendant is a limited partnership registered to conduct business in Minnesota and Texas.

8. Defendant is a "person" as defined in Section 302(e) of the CAA, 42 U.S.C. §7602(e); Section 1004(15) of RCRA, 42 U.S.C. §6903(15); Section 311(a)(7) of the CWA, 42 U.S.C. §1321(a)(7); Section 329(7) of EPCRA, 42 U.S.C. §11049(7); and applicable federal and state regulations promulgated pursuant to these statutes.

STATUTORY AND REGULATORY BACKGROUND

CLEAN AIR ACT REQUIREMENTS

9. The Clean Air Act established a regulatory scheme designed to protect and enhance the quality of the nation's air so as to promote the public health and welfare and the productive capacity of its population. Section 101(b)(1) of the Act, 42 U.S.C. § 7401(b)(1).

10. Prevention of Significant Deterioration. - Section 109 of the Act, 42 U.S.C. § 7409, requires the Administrator of EPA to promulgate regulations establishing primary and secondary national ambient air quality standards ("NAAQS" or "ambient air quality standards") for certain criteria air pollutants. The primary NAAQS are to be adequate to protect the public health, and the secondary NAAQS are to be adequate

to protect the public welfare, from any known or anticipated adverse effects associated with the presence of the air pollutant in the ambient air.

11. Section 110 of the Act, 42 U.S.C. § 7410, requires each state to adopt and submit to EPA for approval a State Implementation Plan ("SIP") that provides for the attainment and maintenance of the NAAQS.

12. Under Section 107(d) of the Act, 42 U.S.C. § 7407(d), each state is required to designate those areas within its boundaries where the air quality is better or worse than the NAAQS for each criteria pollutant, or where the air quality cannot be classified due to insufficient data. These designations have been approved by EPA and are located at 40 C.F.R. Part 81. An area that meets the NAAQS for a particular pollutant is classified as an "attainment" area; one that does not is classified as a "non-attainment" area.

13. Part C of Title I of the Act, 42 U.S.C. §§ 7470-7492, sets forth requirements for the prevention of significant deterioration ("PSD") of air quality in those areas designated as attaining the NAAQS standards. These requirements are designed to protect public health and welfare, to assure that economic growth will occur in a manner consistent with the preservation of existing clean air

resources and to assure that any decision to permit increased air pollution is made only after careful evaluation of all the consequences of such a decision and after public participation in the decision-making process. These provisions are referred to herein as the "PSD program."

14. Section 165(a) of the Act, 42 U.S.C. § 7475(a), prohibits the construction and subsequent operation of a major emitting facility in an area designated as attainment unless a PSD permit has been issued. Section 169(1) of the Act, 42 U.S.C. § 7479(1), defines "major emitting facility" as a source with the potential to emit 250 tons per year (tpy) or more of any air pollutant.

15. As set forth at 40 C.F.R. § 52.21(k), the PSD program generally requires a person who wishes to construct or modify a major emitting facility in an attainment area to demonstrate, before construction commences, that construction of the facility will not cause or contribute to air pollution in violation of any ambient air quality standard or any specified incremental amount.

16. As set forth at 40 C.F.R. § 52.21(i), any major emitting source in an attainment area that intends to construct a major modification must first obtain a PSD permit. "Major modification" is defined at 40 C.F.R. § 52.21(b)(2)(i)

as meaning any physical change in or change in the method of operation of a major stationary source that would result in a significant net emission increase of any criteria pollutant subject to regulation under the Act. "Significant" is defined at 40 C.F.R. § 52.21(b)(23)(i) in reference to a net emissions increase or the potential of a source to emit any of the following criteria pollutants, at a rate of emissions that would equal or exceed any of the following: for ozone, 40 tons per year of volatile organic compounds (VOCs); for carbon monoxide (CO), 100 tons per year; for nitrogen oxides (NO_x), 40 tons per year; for sulfur dioxide (SO₂), 100 tons per year, (hereinafter "criteria pollutants").

17. As set forth at 40 C.F.R. § 52.21(j), a new major stationary source or a major modification in an attainment area shall install and operate best available control technology ("BACT") for each pollutant subject to regulation under the Act that it would have the potential to emit in significant quantities.

18. Section 161 of the Act, 42 U.S.C. § 7471, requires state implementation plans to contain emission limitations and such other measures as may be necessary, as determined under the regulations promulgated pursuant to these provisions, to

prevent significant deterioration of air quality in attainment areas.

19. A state may comply with Section 161 of the Act either by being delegated by EPA the authority to enforce the federal PSD regulations set forth at 40 C.F.R. § 52.21, or by having its own PSD regulations approved as part of its SIP by EPA, which must be at least as stringent as those set forth at 40 C.F.R. § 51.166.

20. Part D of Title I of the Act, 42 U.S.C. §§ 7501-7515, sets forth provisions which direct States to include in their SIPs requirements to provide for reasonable progress towards attainment of the NAAQS in nonattainment areas. Section § 172(c) (5) of the Act, 42 U.S.C. § 7502(c) (5), provides that these SIPs shall require permits for the construction and operation of new or modified major stationary sources anywhere in the nonattainment area, in accordance with Section 173 of the Act, 42 U.S.C. § 7503, in order to facilitate "reasonable further progress" towards attainment of the NAAQS.

21. Section 173 of Part D of the Act, 42 U.S.C. § 7503, requires that in order to obtain such a permit the source must, among other things: (a) obtain federally enforceable emission offsets at least as great as the new source ☒

emissions; (b) comply with the lowest achievable emission rate as defined in Section 171(3) of the Act, 42 U.S.C. § 7501(3); and (c) analyze alternative sites, sizes, production processes, and environmental control techniques for the proposed source and demonstrate that the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification.

22. As set forth in 40 C.F.R. § 52.24, no major stationary source shall be constructed or modified in any nonattainment area as designated in 40 C.F.R. part 81, subpart C ("nonattainment area") to which any SIP applies, if the emissions from such source will cause or contribute to concentrations of any pollutant for which a NAAQS is exceeded in such area, unless, as of the time of application for a permit for such construction, such plan meets the requirements of Part D, Title I, of the Act.

23. A state may comply with Section 172 and 173 of the Act by having its own nonattainment new source review regulations approved as part of its SIP by EPA, which must be at least as stringent as those set forth at 40 C.F.R. § 51.165.

24. Flaring and New Source Performance Standards. -

Section 111 of the CAA, 42 U.S.C. § 7411, requires EPA to promulgate standards of performance for certain categories of new air pollution sources ("New Source Performance Standards" or "NSPS"). Pursuant to Section 111(b), 42 U.S.C. § 7411(b), EPA promulgated general regulations applicable to all NSPS source categories. Those general regulations are set forth at 40 C.F.R. Part 60 Subpart A.

25. EPA's NSPS regulations applicable to petroleum refineries, including requirements for implementing and utilizing good air pollution control practices at all times, are set forth at 40 C.F.R. Part 60 Subpart J. The NSPS requirements establish an emission limit of 250 ppm of SO₂ from the sulfur recovery plants, which represents a 99.9% reduction of SO₂.

26. Leak Detection and Repair. - Section 112 of the CAA, 42 U.S.C. § 7412, requires EPA to promulgate emission standards for certain categories of sources of hazardous air pollutants ("National Emission Standards for Hazardous Air Pollutants" or "NESHAPs") Pursuant to Section 112(d) of the CAA, 42 U.S.C. § 7412(d), EPA promulgated national emission standards for equipment leaks (fugitive emission sources). Those regulations are set forth at 40 C.F.R. Parts 61 Subpart

J and V, and Part 63 Subparts F (National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry), H (NESHAP for Equipment Leaks) and CC (NESHAP for Petroleum Refineries) and Part 60 Subparts VV and GGG.

27. The focus of the LDAR program is the refinery-wide inventory of all possible leaking valves, the regular monitoring of those valves to identify leaks, and the repair of leaks as soon as they are identified.

28. Benzene Waste NESHAP. - The CAA requires EPA to establish emission standards for each "hazardous air pollutant" ("HAP") in accordance with Section 112 of the CAA, 42 U.S.C. § 7412.

29. In March 1990, EPA promulgated national emission standards applicable to benzene-containing wastewaters. Benzene is a listed HAP and a known carcinogen. The benzene waste regulations are set forth at 40 C.F.R. Part 61 Subparts FF, (National Emission Standard for Benzene Waste Operations). Benzene is a naturally-occurring constituent of petroleum product and petroleum waste and is highly volatile. Benzene emissions can be detected anywhere in a refinery where the petroleum product or waste materials are exposed to the ambient air.

30. Pursuant to the Benzene waste NESHAP, refineries are required to tabulate the total annual benzene ("TAB") content in their wastewater. If the TAB is over 10 megagrams, the refinery is required to elect a control option that will require the control of all waste streams, or control of certain select waste streams.

31. Pursuant to Section 113(b) of the CAA, 42 U.S.C. §7413(b), EPA may commence a civil action for injunctive relief and civil penalties for violations of the Act, not to exceed \$25,000 per day of violation for violations of the CAA. Pursuant to Pub. L. 104-134 and 61 Fed. Reg. 69369, civil penalties of up to \$27,500 per day per violation may be assessed for violations occurring on or after January 30, 1997.

Resource Conservation and Recovery Act Requirements

32. RCRA establishes a comprehensive statutory scheme for the management of hazardous wastes from their initial generation until their final disposal. Regulations promulgated pursuant to RCRA regulate generators of hazardous wastes, as well as owners and operators of facilities that treat, store, or dispose of hazardous wastes ("TSD facilities"). The federal regulations implementing RCRA are codified at 40 C.F.R. Part 260 et seq.

33. Under Section 3006(b) of RCRA, 42 U.S.C. § 6926(b), and 40 C.F.R. Part 271, any state may apply for and receive authorization to enforce its own hazardous waste management program in place of the federal hazardous waste management program described in the preceding paragraph, provided the state requirements are consistent with and equivalent to the federal requirements. To the extent that the state hazardous waste program is authorized by EPA pursuant to Section 3006 of RCRA, 42 U.S.C. § 6926, the requirements of the state program are effective in lieu of the federal hazardous waste management program set forth in 40 C.F.R. Part 260 et seq.

34. Minnesota promulgated hazardous waste management regulations and received authorization from EPA to administer various aspects of the hazardous waste management program within Minnesota. On February 11, 1985, the State of Minnesota was granted final authorization by the Administrator of EPA pursuant to Section 3006(b) of RCRA, 42 U.S.C. §6926(b), to administer and enforce a hazardous waste program in the State of Minnesota. (40 C.F.R. § 272.1200).

35. The regulations comprising the applicable State hazardous waste program for the State of Minnesota were incorporated by reference into federal law at 40 C.F.R. §272.1201(a). As a result, facilities in Minnesota operating

without a permit under Section 3005(a) of RCRA, 42 U.S.C. §6925(a), are regulated under the Minnesota provisions found at Minnesota Rules 7001.0010 et seq., in lieu of the federal regulations set forth at 40 C.F.R. Part 260 et seq., except for applicable requirements pursuant to the provisions of the Hazardous and Solid Waste Amendments of 1984 (HSWA) for which Minnesota is not authorized.

36. Section 3008(a) of RCRA, 42 U.S.C. § 6928(a), provides EPA with authority to enforce State regulations in those states authorized to administer a hazardous waste program.

37. Section 3006(g) of RCRA, 42 U.S.C. § 6926(g), provides EPA with authority to implement and enforce those portions of the HSWA requirements for which the State of Minnesota is not authorized.

38. Any violations of regulations promulgated pursuant to Subtitle C, Sections 3001-3009 of RCRA, 42 U.S.C. §§ 6921-6939, or a State provision approved pursuant to Section 3006 of RCRA, subject to the assessment of civil or criminal penalties and compliance orders as provided in Section 3008 of RCRA, 42 U.S.C. § 6928.

39. Pursuant to Section 3008(a) of RCRA, 42 U.S.C. §6928(a), EPA may issue an order assessing a civil penalty for any past or current violation and require compliance.

40. Pursuant to Section 3004(n) of RCRA, 42 U.S.C. §6924(n), EPA promulgated regulations to control and monitor air emissions at hazardous waste treatment, storage, and disposal facilities as necessary to protect human health and the environment.

41. On December 6, 1994, EPA issued a set of these regulations at 40 C.F.R. Parts 264 and 265, Subpart CC. These standards apply to certain tanks, surface impoundments, and containers used to manage hazardous waste. 40 C.F.R. Parts 264 and 265, Subpart CC regulations became effective on December 6, 1996 (61 Fed. Reg. 59932, November 25, 1996).

42. Pursuant to Section 3001(e)(2) of RCRA, 42 U.S.C. §6921(e), EPA promulgated regulations on November 2, 1990, to list new hazardous wastes from non-specific sources at petroleum refineries. The newly listed waste code F037 found at 40 C.F.R. § 261.31 applies to certain surface impoundments that contain any sludge generated from the gravitational separation of oil/water/solids during the storage or treatment of process wastewaters and oily cooling wastewaters from

petroleum refineries. The final rule became effective on May 2, 1991. 55 Fed. Reg. 46354.

43. Pursuant to Section 3006(g) of RCRA, 42 U.S.C. §6926(g), EPA has jurisdiction to carry out directly those portions of the HSWA requirements for which the State is not authorized. The State of Minnesota has not received authorization for the regulations to control air emission standards for tanks, surface impoundments, and containers found at 40 C.F.R. Parts 264 and 265, Subpart CC. The State of Minnesota has not received authorization for the regulation to list F037 waste, found at 40 C.F.R. § 261.31. Thus, EPA has jurisdiction to carry out these standards and listing in Minnesota directly.

44. Pursuant to Section 3006(g) of RCRA, 42 U.S.C. §3006(g) of RCRA, 42 U.S.C. § 6926(g), requirements imposed pursuant to HSWA take effect immediately in all states; therefore, Subpart CC was effective in Minnesota on December 6, 1996, and listed F037 waste was effective in Minnesota on May 2, 1991.

45. Section 3008(g) of RCRA, 42 U.S.C. § 6928(g), provides that any person who violates a requirement of RCRA shall be liable for a civil penalty of up to \$25,000 per day for each such violation. Pursuant to Pub. L. 104-134 and 61

Fed. Reg. 69369, civil penalties of up to \$27,500 per day per violation may be assessed for violations occurring on or after January 30, 1997.

Clean Water Act Requirements

46. Section 311(b)(3) of the CWA, prohibits the discharge of oil into or upon the navigable waters of the United States or adjoining shorelines in such quantities that have been determined may be harmful to the public health or welfare or environment of the United States.

47. The regulation at 40 C.F.R. § 110.3 specifies the quantity of oil that has been determined may be harmful to the public health or welfare or environment of the United States. The quantity of oil includes discharges of oil that cause a film or a sheen upon or discoloration of the surface of the water or adjoining shorelines.

48. Section 311(j)(1)(C) of the CWA, provides that the President shall issue regulations "establishing procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil and hazardous substances from vessels and from onshore facilities and offshore facilities, and to contain such discharges.

CERCLA Requirements

49. Section 103(a) of CERCLA, 42 U.S.C. § 9603(a), requires a person in charge of a facility to immediately notify the National Response Center of a release of a hazardous substance from such facility in an amount equal to or greater than the amount determined pursuant to Section 102 of CERCLA, 42 U.S.C. § 9602 (the "reportable quantity").

50. Section 109(c)(1) of CERCLA, 42 U.S.C. § 9609(c)(1), provides that any person who violates the notice requirements of Section 103(a) of CERCLA, 42 U.S.C. § 9603(a), shall be liable to the United States for civil penalties in an amount not to exceed \$25,000 per day for each day the violation continues, and in an amount not to exceed \$75,000 per day for each day that any second or subsequent violation continues. Pursuant to Pub. L. 104-134 and 61 Fed. Reg. 69369, civil penalties of up to \$27,500 per day for the first violation, and \$82,500 per day for any second or subsequent violations, may be assessed for violations occurring on or after January 30, 1997.

EPCRA Requirements

51. Section 304(a) of EPCRA, 42 U.S.C. § 11004(a), requires the owner and operator of a facility at which a hazardous chemical is produced, used, or stored, to

immediately notify the State Emergency Response Commission ("SERC") and the Local Emergency Planning Committee ("LEPC") of certain specified releases of a hazardous or extremely hazardous substance.

52. Section 304(c) of EPCRA, 42 U.S.C. § 11004(c), requires that, as soon as practicable after a release which requires notice under Section 304(a) of EPCRA, 42 U.S.C. § 11004(a), the owner or operator shall provide a written followup emergency notice providing certain specified additional information.

53. Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3), provides that any person who violates any requirement of Section 304 of EPCRA, 42 U.S.C. § 11004, shall be liable to the United States for civil penalties in an amount not to exceed \$25,000 per day for each day the violation continues, and in an amount not to exceed \$75,000 per day for each day that any second or subsequent violation continues. Pursuant to Pub. L. 104-134 and 61 Fed. Reg. 69369, civil penalties of up to \$27,500 per day for the first violation, and \$82,500 per day for any second or subsequent violations, may be assessed for violations occurring on or after January 30, 1997.

FIRST CLAIM FOR RELIEF
PSD Requirements

54. Paragraphs 1 through 23, and 31 are realleged and incorporated by reference.

55. Koch modified the fluidized catalytic cracking unit ("FCCU") at its Pine Bend refinery in 1994 when it added a blower.

56. Koch modified the FCCU at its Pine Bend refinery in 1999 when it converted to full burning of coke in its regenerator.

57. Each of these modifications was a "major modification" within the meaning of 40 C.F.R. § 52.21(b)(2).

58. Therefore, since at least 1994, Koch has been in violation of Section 165(a) of the Act, 42 U.S.C. § 7475(a), and 40 C.F.R. § 52.21, by failing to undergo PSD review, by failing to obtain a permit, and failing to install BACT for each of the modifications to the Pine Bend refinery cited in this Complaint.

59. Unless restrained by an Order of the Court, these violations of the Act and the implementing regulations will continue.

60. As provided in 42 U.S.C. § 7413(b), Koch's violations, as set forth above, subject it to injunctive

relief and civil penalties of up to \$25,000 per day for each violation of the Act prior to January 30, 1997, and \$27,500 per day for each violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701.

SECOND CLAIM FOR RELIEF
New Source Performance Standards

61. Paragraphs 1 through 9, 24, 25 and 31 are realleged and incorporated by reference.

62. On one or more occasions, since 1995, Koch's refinery flares at its Pine Bend and Corpus Christi West and East refineries have emitted unpermitted quantities of SO₂, a criteria pollutant, under circumstances that did not represent good air pollution control practices, in violation of 40 C.F.R. § 60.11(d) and for combustion of refinery fuel gas in violation of Subpart J, 40 C.F.R. §§ 60.104, et seq.

63. Unless restrained by an Order of the Court, these violations of the Act and the implementing regulations will continue.

64. As provided in 42 U.S.C. § 7413(b), Koch's violations, as set forth above, subject it to injunctive relief and civil penalties of up to \$25,000 per day for each violation of the Act prior to January 30, 1997, and \$27,500

per day for each violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701.

THIRD CLAIM FOR RELIEF
Leak Detection and Repair Requirements

65. Paragraphs 1 through 9, 26, 27 and 31 are realleged and incorporated by reference.

66. Koch is required under 40 C.F.R. Part 60 Subpart GGG, to comply with standards set forth at 40 C.F.R. § 60.592, which in turn references standards set forth at 40 C.F.R. §§ 60.482-1 to 60.482-10, and alternative standards set forth at 40 C.F.R. §§ 60.483-1 to 60.483-2, for certain of its refinery equipment in VOC service, constructed or modified after January 4, 1983,

67. Pursuant to 40 C.F.R. § 60.483-2(b)(1), an owner or operator of subject VOC valves must initially comply with the leak detection monitoring and repair requirements set forth in 40 C.F.R. § 60.482-7, including the use of Standard Method 21 to monitor for such leaks.

68. Pursuant to 40 C.F.R. Part 61 Subpart J, Koch is required to comply with the requirements set forth in 40 C.F.R. Part 61, Subpart V, for certain specified equipment in benzene service.

69. On numerous occasions since December 31, 1995, Koch failed to accurately monitor the subject VOC valves and other components at the Pine Bend and Corpus Christi West refineries as required by Standard Method 21, to report the VOC valves and other components that were leaking, and to repair all leaking VOC valves and other components in a timely manner.

70. On at least one occasion, since 1995, Koch failed to monitor over 500 valves at its Pine Bend refinery that were subject to the above described requirements.

71. Koch's acts or omissions referred to in the preceding paragraphs constitute violations of the NSPS and Benzene Waste NESHAP.

72. Unless restrained by an Order of the Court, these violations of the Act and the implementing regulations will continue.

73. As provided in 42 U.S.C. § 7413(b), Koch's violations, as set forth above, subject it to injunctive relief and civil penalties of up to \$25,000 per day for each violation of the Act prior to January 30, 1997, and \$27,500 per day for each violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701.

FOURTH CLAIM FOR RELIEF
Benzene Waste NESHA

74. Paragraphs 1 through 9, and 28 through 31 are realleged and incorporated by reference.

75. At all times relevant to this Complaint, Koch has elected to comply with identified benzene waste management and treatment options set forth in 40 C.F.R. § 61.342 for its benzene waste streams at each of its refineries.

76. Pursuant to 40 C.F.R. § 61.342, the benzene quantity for wastes must be equal to or less than 2.0 megagrams or 6.0 megagrams per year as defined for the applicable option identified, as selected by the refinery.

77. Koch's 1998 annual report for its Pine Bend and Corpus Christi West refineries indicate that the benzene quantity for its described and defined wastes exceeded 2.0 megagrams, in violation of the benzene waste regulations and the Act.

78. Unless restrained by an Order of the Court, these violations of the Act and the implementing regulations will continue.

79. As provided in 42 U.S.C. § 7413(b), Koch's violations, as set forth above, subject it to injunctive relief and civil penalties of up to \$25,000 per day for each

violation of the Act prior to January 30, 1997, and \$27,500 per day for each violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701.

FIFTH CLAIM FOR RELIEF
RCRA

80. Paragraphs 1 through 8, and 32 through 45 are realleged and incorporated by reference.

81. EPA issued an administrative complaint to Koch, Docket No. RCRA-5-2000-010, on August 31, 2000, a copy of which is attached hereto and incorporated herein by reference. The United States realleges the acts or omissions referred to in the administrative complaint.

82. The acts or omissions referred to in the preceding paragraph, and reflected in the attached administrative complaint, constitute violations of RCRA.

83. Unless restrained by an Order of the Court, these violations of RCRA and the implementing regulations will continue.

84. Pursuant to Section 3008(a) and (g) of RCRA, 42 U.S.C. § 6928(a) and (g), Pub. L. 104-134 and 61 Fed. Reg. 69,360 (Dec. 31, 1996), Koch's violations as set forth above subject it to subject it to injunctive relief and civil

penalties of up to \$25,000 per day for each violation of the Act prior to January 30, 1997, and \$27,500 per day for each violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. §2461, as amended by 31 U.S.C. §3701.

SIXTH CLAIM FOR RELIEF
CLEAN WATER ACT

85. Paragraphs 1 through 8, and 46 through 48 are realleged and incorporated by reference.

86. Section 311(b)(3) of CWA, 33 U.S.C. § 1321(b)(3), prohibits the discharge of oil or hazardous substances into or upon the navigable waters of the United States, adjoining shorelines, or into or upon the waters of the contiguous zone in such quantities as may be harmful.

87. Section 311(j) of CWA, 33 U.S.C. § 1321(j), requires EPA to issue regulations, inter alia, establishing criteria for the development and implementation of local and regional oil and hazardous substance removal contingency plans, establishing procedures, methods and equipment to prevent discharges of oil and hazardous substances from vessels and from onshore facilities and offshore facilities, and to contain such discharges.

88. Koch has violated Section 311(b)(3) of CWA, 33 U.S.C. § 1321(b)(3), for its discharge of oil from Tank 16 at its Pine Bend facility into or upon the navigable waters of the United States, adjoining shorelines, or into or upon the waters of the contiguous zone in such quantities as may be harmful.

89. The regulation at 40 C.F.R. § 112.3(b) requires an owner or operator of an onshore facility that became operational after the effective date to prepare a Spill Prevention Control and Countermeasure ("SPCC") plan no later than six months after the date the facility started operations if the facility has violated or could reasonably be expected to violate 40 C.F.R. Parts 110 and 112.

90. Koch failed to prepare an adequate SPCC plan for its facility in violation of the regulation at 40 C.F.R. § 112.3(b).

91. Unless restrained by an Order of the Court, these violations of the Act and the implementing regulations will continue.

92. Pursuant to Section 309 of CWA, 33 U.S.C. § 1319, Koch is liable for civil penalties in an amount not to exceed \$25,000 per day for each day the violation continues for each such violation occurring prior to January 30, 1997, and

\$27,500 per day for each violation after January 30, 1997, pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701.

SEVENTH CLAIM FOR RELIEF
CERCLA

93. Paragraphs 1 through 8, 49 and 50 are realleged and incorporated by reference.

94. Section 103(a) of CERCLA, 42 U.S.C. § 9603(a), requires a person in charge of a facility to immediately notify the National Response Center of a release of a hazardous substance from such facility in an amount equal to or greater than the amount determined pursuant to Section 102 of CERCLA, 42 U.S.C. § 9602 (the "reportable quantity").

95. On fourteen days between January 1, 1997 and December 31, 1999, Koch failed to immediately notify the National Response Center of releases from its Pine Bend facility of hazardous substances in an amount equal to or greater than the reportable quantity for those substances.

96. The acts or omissions referred to in the preceding paragraph constitute violations of Section 103(a) of CERCLA, 42 U.S.C. § 9603.

97. Pursuant to Section 109(c)(1) of CERCLA, 42 U.S.C. § 9609(c)(1), Koch is liable for civil penalties in an amount not to exceed \$25,000 per day for each day the violation continues for each such violation occurring prior to January 30, 1997, and pursuant to Section 109(c)(1) of CERCLA, 42 U.S.C. § 9609(c)(1), Pub.L. 104-134 and 61 Fed. Reg. 69360, civil penalties of up to \$27,500 per day for each such violation occurring on or after January 30, 1997; and in an amount not to exceed \$75,000 per day for each day that any second or subsequent violation continues for each such violation occurring prior to January 30, 1997, and pursuant to Section 109(c)(1) of CERCLA, 42 U.S.C. § 9609(c)(1), Pub.L. 104-134 and 61 Fed. Reg. 69360, civil penalties of up to \$82,500 per day for each such violation occurring on or after January 30, 1997.

EIGHTH CLAIM FOR RELIEF
EPCRA

98. Paragraphs 1 through 8, and 53 are realleged and incorporated by reference.

99. Section 304(a) of EPCRA, 42 U.S.C. § 11004(a), requires the owner and operator of a facility at which a hazardous chemical is produced, used, or stored, to immediately notify the State Emergency Response Commission

("SERC" - State Authority) and the Local Emergency Planning Committee ("LEPC" - Local Authority) of certain specified releases of a hazardous or extremely hazardous substance.

100. Section 304(c) of EPCRA, 42 U.S.C. § 11004(c), requires that, as soon as practicable after a release which requires notice under Section 304(a) of EPCRA, 42 U.S.C. § 11004(a), the owner or operator shall provide a written followup emergency notice providing certain specified additional information.

101. On five days between January 1, 1997 and December 31, 1999, Koch failed to immediately notify the SERC (State Authority) of a release of a hazardous or extremely hazardous substance as required by Section 304(a) of EPCRA, 42 U.S.C. § 11004(a).

102. On five days between January 1, 1997 and December 31, 1999, Koch failed to immediately notify the LEPC (Local Authority) of a release of a hazardous or extremely hazardous substance as required by Section 304(a) of EPCRA, 42 U.S.C. § 11004(a).

103. On five days between January 1, 1997 and December 31, 1999, Koch failed to provide a written followup emergency notice to the SERC (State Authority) as soon as practicable after a release which requires notice under Section 304(a) of

EPCRA, 42 U.S.C. § 11004(a), in accordance with the requirements of Section 304(c) of EPCRA, 42 U.S.C. § 11004(c).

104. On five days between January 1, 1997 and December 31, 1999, Koch failed to provide a written followup emergency notice to the LEPC (Local Authority) as soon as practicable after a release which requires notice under Section 304(a) of EPCRA, 42 U.S.C. § 11004(a), in accordance with the requirements of Section 304(c) of EPCRA, 42 U.S.C. § 11004(c).

105. The acts or omissions referred to in the preceding paragraphs constitute violations of Section 304 of EPCRA, 42 U.S.C. § 11004.

106. Pursuant to Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3), Koch is liable for civil penalties in an amount not to exceed \$25,000 per day for each day the violation continues for each such violation occurring prior to January 30, 1997, and pursuant to Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3), Pub.L. 104-134 and 61 Fed. Reg. 69360, civil penalties of up to \$27,500 per day for each such violation occurring on or after January 30, 1997; and in an amount not to exceed \$75,000 per day for each day that any second or subsequent violation continues for each such violation occurring prior to January 30, 1997, and pursuant to Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3), Pub.L.

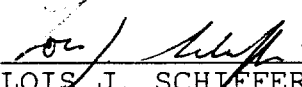
104-134 and 61 Fed. Reg. 69360, civil penalties of up to \$82,500 per day for each such violation occurring on or after January 30, 1997.

PRAYER FOR RELIEF


WHEREFORE, Plaintiff, the United States, respectfully requests that this Court:

1. Order Koch to immediately comply with the statutory and regulatory requirements cited in this Complaint, under the Clean Air Act, the Clean Water Act, RCRA, CERCLA and EPCRA;
2. Order Koch to take appropriate measures to mitigate the effects of its violations;
3. Assess civil penalties against Koch for up to the amounts provided in the applicable statutes; and
4. Grant the United States such other relief as this Court deems just and proper.

Respectfully submitted,



LOIS J. SCHIFFER
Assistant Attorney General
Environment and Natural Resources
Division
U.S. Department of Justice

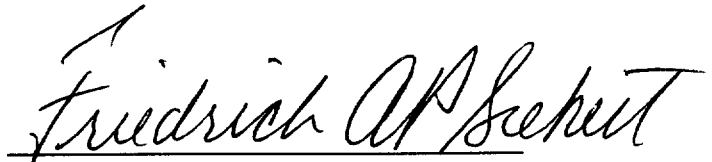


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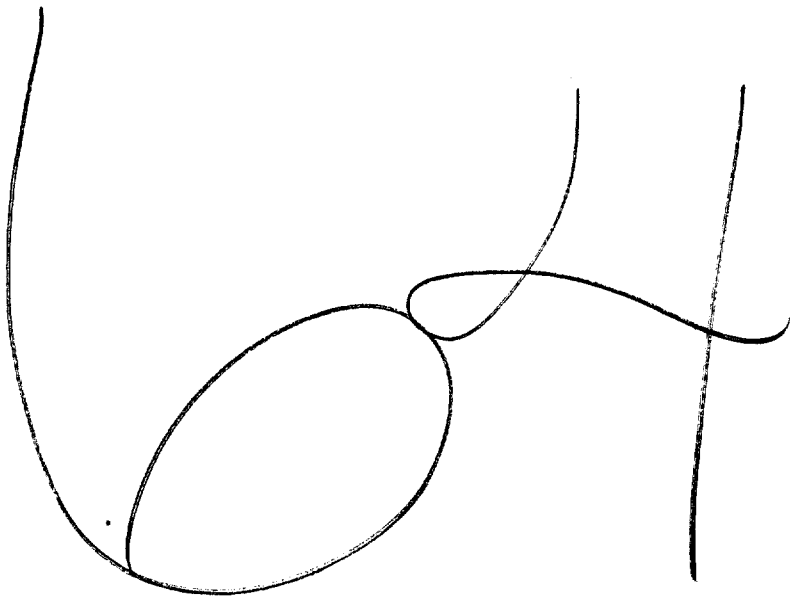


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A handwritten signature or set of initials in black ink. It features a large, open 'U' shape on the left, followed by a large oval, and then a series of loops and a vertical line on the right.

UNITED STATES DISTRICT COURT
DISTRICT OF MINNESOTA

United States of America,

Civil Action No.00-CV-2756 *PAM/SE*

Plaintiff,

and

State of Minnesota, by the Minnesota
Pollution Control Agency,

Plaintiff-Intervenor,

vs.

COMPLAINT

Koch Petroleum Company, L.P.,

Defendant.

A true copy in 8 sheet (s)
of the record in my custody.
CERTIFIED 9/7 2001
BY: Richard D. Sletten, Clerk
Donna J. Daulton
Deputy Clerk

Plaintiff-Intervenor, State of Minnesota, by its Attorney General, Mike Hatch, acting at
the request of the Minnesota Pollution Control Agency ("MPCA"), alleges:

NATURE OF THE ACTION

1. This is a civil action brought against Koch Petroleum Group, L. P. ("Koch" or
"Defendant") to obtain injunctive relief and assessment of civil penalties for past and ongoing
violations of the Clean Air Act ("CAA" or "Act"), 42 U.S.C. § 7401 *et seq.*, and Minnesota's air
pollution laws, Minn. Stat. §§ 115.071 and 116.07 and Minn. R. 7011.1435, at Koch's Pine Bend
Refinery in Rosemount, Minnesota. The violations alleged in the Complaint occurred and are
occurring at Koch's Pine Bend Refinery.

FEB 27 2001
FILED
FRANCIS E. DORAL, CLERK
JUDGMENT ENTERED
DEPUTY CLERK'S INITIALS

5

JURISDICTION AND VENUE

2. This Court has jurisdiction to hear this civil action brought by the State of Minnesota pursuant to Rule 24 of the Federal Rules of Civil Procedure. This Court has jurisdiction over the subject matter of this action pursuant to 28 U.S.C. §§ 1331, 1345, and 1355, and Section 113(b) of the CAA, 42 U.S.C. § 7413(b).

3. Venue is proper in this district pursuant to 28 U.S.C. §§ 1391 and 1395, and Section 113(b) of the CAA, 42 U.S.C. § 7413(b), because the violations alleged herein occurred at Defendant's Pine Bend Refinery, which is located in this district.

DEFENDANT

4. Defendant is a limited partnership organized and existing under the laws of the State of Delaware, and is authorized to do business and is doing business in the State of Minnesota.

5. Defendant owns and operates a petroleum refinery ("Pine Bend Refinery") located in the Pine Bend industrial area of Rosemount, Minnesota, at the junction of Highways 52 and 55 in the County of Dakota, State of Minnesota.

6. Defendant is a "person" as defined in Section 302(e) of the CAA, 42 U.S.C. § 7602 (e), and applicable Minnesota statute and regulations promulgated pursuant to the CAA.

CLEAN AIR ACT REQUIREMENTS

7. The Clean Air Act established a regulatory scheme designed to protect and enhance the quality of the nation's air so as to promote the public health and welfare and the productive capacity of its population. Section 101(b)(1) of the Act, 42 U.S.C. § 7401(b)(1).

8. Section 109 of the Clean Air Act, 42 U.S.C. § 7409, requires the U.S. Environmental Protection Agency ("EPA") to promulgate regulations establishing primary and secondary national ambient air quality standards ("NAAQS") for certain criteria air pollutants. The primary NAAQS shall be sufficient to protect the public health, allowing an adequate margin of safety, and the secondary NAAQS shall be sufficient to protect the public welfare from any known or anticipated adverse effects associated with the presence of the air pollutant in the ambient air. The NAAQS promulgated by the EPA are set forth at 40 C.F.R. Part 50.

9. Section 110 of the CAA, 42 U.S.C. § 7410, required each state to adopt and submit to EPA for approval a State Implementation Plan ("SIP") that provides for the attainment and maintenance of the NAAQS.

10. Pursuant to Section 110 of the CAA, 42 U.S.C. § 7410, portions of the Minnesota SIP, including Minnesota Rule Part 7011.1435, have been submitted to and approved by EPA.

11. Pursuant to Section 110 of the CAA, 42 U.S.C. § 7410, Minnesota's operating permit program was submitted to and approved by EPA. Pursuant to EPA's approval of Minnesota's operating permit program and other EPA delegations of authority, certain air permits issued by Minnesota are federally enforceable. Such permits are also enforceable by the State of Minnesota pursuant to Minnesota Statutes Chapters 115.071 and 116.07.

12. Minnesota Statutes Chapter 115.071 provides, inter alia, that any failure by a person to comply with the terms and conditions of a state issued permit shall render such person subject to enforcement action pursuant to Minnesota Statutes Chapter 115.071, subdivisions 1 through 6.

13. Pursuant to Minnesota Statute Chapter 115.071, Plaintiff-Intervenor Minnesota may commence a civil action for injunctive relief and for civil penalties not to exceed \$10,000 for each violation per day for each day such violation may continue.

14. Plaintiff-Intervenor Minnesota notified Koch on or about December 1999 that Koch was in violation of certain terms and conditions of state air emission permits 106A-85-OT-1 and 106A-92-I/O-32, and thereby was in violation of Minnesota Statute § 115.071.

15. Section 111 of the Clean Air Act, 42 U.S.C. § 7411, requires EPA to promulgate standards of performance for certain categories of new air pollution sources ("New Source Performance Standards" or "NSPS").

16. Pursuant to Section 111(b) of the Clean Air Act, 42 U.S.C. § 7411(b), EPA promulgated general regulations applicable to all NSPS source categories. Those regulations are set forth at 40 C.F.R. Part 60.

17. EPA's NSPS regulations applicable to petroleum refineries, including requirements for implementing and utilizing good air pollution control practices at all times, are set forth at 40 C.F.R. Part 60, Subparts A and J. The NSPS requirements establish an emission limit of 250 ppm of sulfur dioxide ("SO₂") from the sulfur recovery plants, which represents a 99.9% reduction of SO₂.

18. Minn. R. 7011.1435 (A) incorporates into state law by reference the requirements of 40 C.F.R. Part 60, Subpart J. 40 C.F.R. Section 60.104(a)(2)(i) addresses the standards for sulfur oxides, and provides that no owner or operator subject to the provisions of this subpart shall, among other things, " ...discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control

system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO₂) at zero percent excess air.”

19. Koch’s air emission permit 106A-85-OT-1, Special Condition II.B, provides that notwithstanding the total emission facility SO₂ limit established in 40 C.F.R. Part 60, Subpart J, Section 60.104(a)(2)(I), Koch shall not allow a source to exceed any emission limit listed below:

Source Nos.	Emission Limitation	Limitation Basis
2	250 ppm by volume on a dry gas and O ₂ free basis, if SRU 3 is operated alone	40 C.F.R. Part 60.104 New Source Performance Standards
	250 ppm by volume on a dry gas and O ₂ free basis	40 C.F.R. Part 60.104 New Source Performance Standards

20. By reviewing information submitted to the MPCA by Koch in 1999, the MPCA discovered that Koch exceeded the above limit on SO₂ emissions from the following emission units:

- Sulfur Recovery Units 3 and 4: 2.2 % of the second quarter (4 days) of 1999; 1.6 % of the third quarter (3 days) of 1999; and 0.61% of the fourth quarter (1 day) of 1999;
- Sulfur Recovery Unit 5: 4.2% of the second quarter (5 days) of 1999.

21. Upon review of the causes of the excess emissions, MPCA staff determined that these exceedences were not “malfunctions” as defined in 40 C.F.R. § 60.2, and, as a result, Koch violated the SO₂ emission limits.

22. Koch’s air emission permit 106A-92-I/O-32 sets the emission limits for SO₂ for the OSWWTP thermal oxidizer stacks at 3.57 lb/MMBTU.

23. By reviewing information submitted to the MPCA by Koch in 1999, the MPCA discovered that Koch exceeded this emission limit during 31.5% of the third quarter (29 days) and 20.64% of the fourth quarter (19 days) of 1999.

24. Upon review of the causes of the excess emissions, MPCA staff determined that Koch violated the SO₂ emission limit.

25. Koch's FESOP Permit 106A-92-I/O-32 provides that the emission limits for particulate matter ("PM") from the fluid catalytic cracking unit ("FCCU") are 1.0 pounds of PM per 1000 pounds of coke burned.

26. By reviewing information submitted to the MPCA by Koch, the MPCA discovered that Koch had bypassed the FCCU control equipment and thus had emissions in excess of the PM limit 2.4 % of the second quarter (7 days) of 1999.

27. Upon review of the causes of the excess emissions, MPCA staff determined that Koch violated the PM emission limit.

28. Minn. R. 7011.1435(C) incorporates into state law by reference the requirements of 40 C.F.R. Part 60, Subpart QQQ, Section 60.692-5(a), which requires that enclosed combustion devices be designed and operated to reduce volatile organic compounds ("VOC") emissions vented to them with an efficiency of 95% or greater or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 degrees Celsius.

29. Koch's air emission permit 106A-92-I/O-32 requires it to maintain the minimum operating temperature in Subpart QQQ Section 60.692-5(a) for the thermal oxidizers at the oil separation waste water treatment plant ("OSWWTP") at the Pine Bend Refinery.

30. By reviewing information submitted to the MPCA by Koch in 1999, the MPCA discovered that Koch failed to maintain the minimum operating temperature of the thermal

oxidizers at the OSWWTP on 12 occasions, totaling 25.45 hours, during the fourth quarter of 1999.

31. Upon review of the causes for the failure to meet the minimum temperature requirement, the MPCA determined that Koch violated the minimum temperature requirement.

32. Koch's air emission permit 106A-92-I/O-32 provides that the emission limits for NO_x from emission unit 27H-1 shall not exceed 0.10 lb/MMBTU on a 24 hour average.

33. By reviewing information submitted to the MPCA by Koch, the MPCA discovered that Koch exceeded the emission limits for NO_x from 27H-1 for 2.1 % of the first quarter (4 days) of 1999 and for 1.99 % of the fourth quarter (3 days) of 1999. As a result, Koch violated the NO_x emission limits.

34. Koch's air emission permit 106A-92-I/O-32 provides that the emissions from heater 27H-102 shall not exceed 0.08 lb/MMBTU on a 24 hour average.

35. By reviewing information submitted to the MPCA by Koch, the MPCA discovered that Koch exceeded its NO_x limit during 5.17% of the second quarter (6 days) of 1998 and 10.5% of the first quarter (10 days) of 1999. As a result, Koch violated the NO_x emission limits.

36. Koch's air emission permit 106A-92-I/O-32 provides that the emission limits for NO_x from emission unit 26H-21 shall not exceed 2.44 lb/MMBTU on a 24 hour average.

37. By reviewing information submitted to the MPCA by Koch, the MPCA discovered that Koch exceeded the emission limits for NO_x from 26H-21 for 5.4 % of the second quarter of 1999. As a result, Koch violated the NO_x emission limits.

PRAYER FOR RELIEF

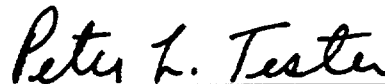
WHEREFORE, Plaintiff-Intervenor, State of Minnesota, respectfully requests this Court:

1. Order Defendant to comply with the CAA and its implementing federal and state regulations and permits;
2. Order Defendant to take appropriate measures to mitigate the effects of its violations of the CAA;
3. Assess civil penalties against Defendant for up to the amounts provided in applicable statutes; and
4. Grant the State of Minnesota such other relief as this Court deems just and proper.

Dated: February 22, 2001

Respectfully submitted,

MIKE HATCH
Attorney General
State of Minnesota



PETER L. TESTER
Assistant Attorney General
Atty. Reg. No. 222525

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ATTORNEYS FOR PLAINTIFF-
INTERVENOR STATE OF MINNESOTA

LS

ORIGINAL

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MINNESOTA

A true copy in 161 sheet (s)
of the record in my custody.
CERTIFIED 9-7 2001
BY: Richard D. Sletten, Clerk
Deputy Clerk

UNITED STATES of AMERICA,)
)
Plaintiff,)
and)
THE STATE OF MINNESOTA,)
)
Plaintiff-Intervener,)
)
v.)
)
KOCH PETROLEUM GROUP, L.P.)
)
Defendant.)
_____)

Civil Action

No. 00-2756 (PAM/SRN)

CONSENT DECREE

FILED APR 25 2001
FRANCIS E. DOSAL, CLERK
JUDGMENT ENTD
DEPUTY CLERK IKC

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UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MINNESOTA

UNITED STATES of AMERICA,)	
)	
Plaintiff,)	
and)	
THE STATE OF MINNESOTA,)	
)	
Plaintiff-Intervener,)	
)	
v.)	Civil Action
)	No.
KOCH PETROLEUM GROUP, L.P.)	
)	
Defendant.)	
_____)	

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America (hereinafter "Plaintiff" or "the United States"), on behalf of the United States Environmental Protection Agency (herein, "EPA"), has simultaneously filed a Complaint and lodged this Consent Decree against Defendant, Koch Petroleum Group, L.P. (herein, "Koch" or "Defendant"), for alleged violations at three petroleum refineries owned and operated by Koch, the Pine Bend, Minnesota refinery, and the East and West refineries in Corpus Christi, Texas;

WHEREAS, prior to the filing of the Complaint, Koch met with representatives from EPA to discuss reconciling EPA and

industry goals for progressive Clean Air Act compliance at Koch's three refineries;

WHEREAS, Koch and EPA's primary common goal in this Consent Decree is to address particular areas of concern: Control of fugitive emissions, elimination of excess flaring, and reduction of nitrogen oxides ("NO_x") and sulfur dioxide ("SO₂") emissions from refinery process units (collectively referred to as "Marquee issues"), in which Koch has agreed to undertake major and extensive program enhancements involving both installation of air pollution control equipment and establishment of strict management practices to reduce air emissions from its refineries;

WHEREAS, the parties agree that the installation of equipment and implementation of controls pursuant to this Consent Decree will achieve major improvements in air quality control, and also that certain actions that Koch has agreed to take are expected to achieve advances in technology and methodology for air pollution control;

WHEREAS, Koch is the first petroleum company to step forward and enter into a comprehensive settlement with EPA addressing this broad range of air pollution control;

WHEREAS, Koch has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, the United States' Complaint alleges that Koch has been and is in violation of certain provisions of the following statutes and their implementing regulations: the Clean Air Act (the "Act"), 42 U.S.C. §§ 7470-7492; the Resource Conservation and Recovery Act, ("RCRA"), 42 U.S.C. § 6901 et seq.; the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), 42 U.S.C. § 9603(a); the Emergency Planning and Community Right to Know Act ("EPCRA"), 42 U.S.C. § 11004(a); and the Clean Water Act ("CWA"), 33 U.S.C. § 1321(b)(3) and (j);

WHEREAS, the State of Minnesota has filed a Complaint in Intervention, alleging that Koch was and is in violation of the applicable State Implementation Plan ("SIP");

WHEREAS, the State of Texas participated in the discussions regarding this Consent Decree and the Texas Natural Resources Conservation Commission ("TNRCC") has expressed general approval of its terms;

WHEREAS, Koch has denied and continues to deny the violations alleged in each of the Complaints; maintains that it has been and remains in compliance with all applicable environmental regulations, and is not liable for civil penalties or injunctive relief; however, in the interest of settlement and to accomplish its objective of cooperatively working to reconcile EPA and industry goals under the Clean

Air Act, has agreed to undertake installation of air pollution control equipment and enhancements to its air pollution management practices at the three refineries to reduce air emissions;

WHEREAS, the parties acknowledge that this process, which was initiated by Koch, is an innovative approach to resolve potential compliance issues while simultaneously advancing the goals of the Clean Air Act;

WHEREAS, Koch has waived any applicable federal or state requirements of statutory notice of the alleged violations;

WHEREAS, the United States, Plaintiff-Intervener, and Koch have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States, Plaintiff-Intervener, and Koch have consented to entry of this Consent Decree without trial of any issues.

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaints, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. The Complaints state a claim upon which relief can be granted against the Defendant under Sections 113 and 167 of

the CAA, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355. This Court has jurisdiction of the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the CAA, 42 U.S.C. §§ 7413 and 7477 and Section 3008(a) of RCRA, 42 U.S.C. § 6928(a), Section 109(c) of CERCLA, 42 U.S.C. § 9609(c), Section 325(b) of EPCRA, 42 U.S.C. § 11045(b), and Section 309(b) of the CWA, 33 U.S.C. § 1319(b). Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), Section 3008(a) of RCRA, 42 U.S.C. § 6928(a), Section 109(c) of CERCLA, 42 U.S.C. § 9609(c), Section 325(b) of EPCRA, 42 U.S.C. § 11045(b), and Section 309(b) of the CWA, 33 U.S.C. § 1319(b), and under 28 U.S.C. § 1391(b) and (c).

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United States, the Plaintiff-Intervener, and upon the Defendant as well as the Defendant's officers, employees, agents, successors and assigns, and shall apply to Defendant's refineries for the life of the Decree. In the event Defendant proposes to sell or transfer any of its refineries subject to this Consent Decree, it shall advise in writing to such proposed purchaser or successor-in-interest of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt

requested, to EPA before such sale or transfer, if possible, but no later than the closing date of such sale or transfer.

III. FACTUAL BACKGROUND

3. Koch operates three petroleum refineries for the manufacture of various petroleum-based products, including gasoline, diesel, and jet fuels, and other marketable petroleum by-products.

4. Koch's Pine Bend refinery has the capacity to process approximately 285,000 barrels per day of heavy crude oil. The total capacity of Koch's Corpus Christi East and West refineries is approximately 285,000 barrels per day.

5. Petroleum refining involves the physical, thermal and chemical separation of crude oil into marketable petroleum products.

6. The petroleum refining process at Koch's three refineries results in emissions of significant quantities of criteria air pollutants, including nitrogen oxides ("NO_x"), carbon monoxide ("CO"), particulate matter ("PM"), and sulfur dioxides ("SO₂"), as well as volatile organic compounds ("VOCs"), including Benzene. The primary sources of these emissions are the fluidized catalytic cracking units ("FCCUs"), process heaters and boilers, the sulfur recovery plants, the wastewater treatment system, fugitive emissions

from leaking components, and flares throughout the refinery where excess emissions are combusted.

IV. POLLUTION REDUCTION MEASURES

A. NO_x Emissions Reductions from Heaters and Boilers

Program Summary: Koch will implement a program to reduce NO_x emissions from refinery heaters and boilers over 40 mmBTU/hr. higher heating value ("HHV") by installing ultra low-NO_x burners ("ULNB"), the demonstration of "next generation" ultra low-NO_x burners, or an alternative emissions reduction technology, and demonstrating compliance with the lower emission limits specified within this Consent Decree with the use of source testing, continuous emissions monitoring systems ("CEMS"), and/or parametric monitoring. Installation of ultra low NO_x burner technology is not required for heaters and boilers less than 40 mmBTU/hr(HHV).

7. By March 31, 2001, Koch shall submit to EPA, an initial plan for NO_x emissions reductions from heaters and boilers. This plan shall be in writing and shall contain the following:

(a.) An inventory of all heaters and boilers at each refinery and their size;

(b.) Identification of all heaters and boilers over 40 mmBTU/hr(HHV) now fitted with ultra low-NO_x burners;

(c.) Identification of all heaters and boilers over 40 mmBTU/hr(HHV) where Koch expects to install "current generation" ultra low-NO_x burners and the projected date of installation;

(d.) Identification of all heaters and boilers over 40 mmBTU/hr(HHV) where Koch plans to demonstrate "next generation" ultra low-NO_x burners and the projected date of installation;

(e.) Identification of all heaters and boilers over 40 mmBTU/hr(HHV) where it is not now expected to be technologically feasible to install or operate current generation or next generation ultra low-NO_x burners (Preliminary Infeasibility List);

(f) Demonstration that requirements of Paragraphs 14 and 17 will be met; and

(g) Identification of all CEMS and parametric monitoring to be installed and the projected date of installation.

Koch will update this plan annually as further discussed in Paragraph 22 of this Consent Decree.

8. For purposes of this Consent Decree, "current generation" ultra low-NO_x burner means those burners currently available on the market that are designed to achieve a NO_x emission rate of 0.03 to 0.04 lb/mmBTU (HHV), when firing natural gas at "typical" industry firing conditions at full design load.

9. For purposes of this Consent Decree, "next generation" ultra low-NO_x burner shall mean those burners new to the market that are designed to an emission rate of 0.012 to 0.015 lb/mmBTU (HHV), when firing natural gas at "typical" industry firing conditions at full design load.

10. For those heaters and boilers identified in Paragraph 7(c) above, Koch shall begin installing current generation ultra low-NO_x burners (ULNB), as defined above and

where determined to be technologically feasible, during the scheduled turnaround (t/a) for each unit that commences on or after August 1, 2001, or for heaters 11H-3, 11H-4 and 11H-5, where t/a commences on or after December 31, 2001. Koch will install the new burners to achieve the lowest feasible emissions of NO_x at maximum representative operating conditions. Subsequent to the development of the initial plan, see Paragraph 7, where warranted, and considering the requirements of Paragraphs 14 and 17, Koch may move heaters and boilers between categories in Paragraph 7. Koch will discuss these changes in the annual plan update.

11. For those heaters and boilers identified in Paragraph 7(d) above, Koch shall demonstrate next generation ultra low-NO_x burners, as defined above, for a test period beginning December 31, 2001. Koch will operate the new burners to achieve the lowest feasible emissions of NO_x at maximum representative operating conditions.

12. Koch shall prepare a written evaluation of the next generation ultra low-NO_x burner demonstration to include a discussion of effectiveness and economic and technical feasibility. Koch shall submit its report to EPA no later than March 31, 2002.

13. If EPA determines that the demonstration of next generation ultra low-NO_x burners is successful, based on Koch's written evaluation of the demonstration, to include design rate, emission rate and heater reliability, and such other information as may then be available to EPA, Koch shall install the "next generation" burners on all heaters and boilers, where feasible, with t/a dates that commence on or after one year following EPA's notice to Koch that the demonstration was successful. Heaters and boilers that meet the "netting unit" definition as of said date (one year after EPA's notice to Koch), will not require additional modification.

14. For heaters and boilers identified in Koch's Preliminary Infeasibility Lists, as updated, Koch shall design and install an alternative emission reduction technology that achieves a weighted average emission limit in lbs NO_x/mmBTU, separately for Pine Bend and for Corpus Christi East and West combined, of not more than 0.06 lb/mmBTU (HHV), based on total emissions and total firing capacities of the heaters and boilers on those lists, by no later than December 31, 2006.

15. By no later than December 31, 2005, Koch shall submit to EPA a Final Determination of Infeasibility, which will include those heaters and boilers which Koch proposes to

exempt, on the basis of technological or economical infeasibility, from further burner technology upgrades for NO_x control as required under Paragraphs 10 and 14. Koch shall include in the Final Determination its basis for the determination of infeasibility.

16. By no later than December 31, 2006, Koch will have installed current or next generation ultra low-NO_x burners, or an alternate emission reduction technology as specified in Paragraph 14, on all heaters and boilers of over 40 mmBTU/hr (HHV), except for those identified pursuant to Paragraph 15 of this Consent Decree.

17. In the event that Koch is successful in limiting the number of heaters or boilers in the technologically infeasible category to:

- (a.) No more than three (3) at Pine Bend and ~~three~~
(3) at the combined Corpus Christi East and West refineries, and with a total of no more than four
(4) across all the refineries; or
- (b.) No more than one heater or boiler separately for Pine Bend and for Corpus Christi East and West combined;

then no further controls will be necessary for these heaters or boilers, they will be considered as "netting units" as that

term is defined in Part IV, Section D of this Consent Decree, and the provisions relating to a weighted average of emission limits of not more than 0.06 lb NO_x per mmBTU/hr(HHV) will not apply. [EXAMPLE: if Pine Bend has only one heater or boiler that is in the technological infeasibility category, but the Corpus refineries have 7 in the technologically infeasible category, the requirements in Paragraph 14 would not apply to the Pine Bend unit, but would apply to all 7 of the Corpus Christi East and West units.]

18. Nothing in this Part shall exempt Koch from complying with any and all other state, regional or federal requirements.

19. If Koch demonstrates, reports to EPA, and EPA determines, that Koch is complying with the Tier II gasoline requirements 40 C.F.R. §§ 80.195-80.205 earlier than their applicable compliance date, the deadline identified in Paragraph 16 (December 31, 2006) shall be extended by a period equal in time to the amount of Koch's early compliance with Tier II deadlines, on a refinery-by-refinery basis.

20. On heaters and boilers with capacity of 150 mmBTU/hr (HHV) or greater, Koch shall install CEMS for NO_x at the time the heaters and boilers are fitted with control technology under this Consent Decree.

21. On heaters and boilers with a capacity less than 150 mmBTU/hr(HHV) that are fitted with control technology under this Consent Decree, Koch shall conduct an initial performance test at maximum representative operating conditions. For heaters and boilers of greater than or equal to 100 mmBTU/hr(HHV) but less than 150 mmBTU/hr(HHV), Koch shall propose operating parameters to be monitored to determine future compliance based on good engineering judgment to ensure that the parameters are most representative for predicting emissions. At a minimum these parameters shall include combustion O₂ and air preheat temperature.

Recordkeeping and Reporting Requirements for Section A

22. Koch shall submit an annual update to the Initial Plan by March 31st of each calendar year regarding the NO_x heater and boiler project and the requirements of this Section. This report shall contain:

- (a.) A list of all heaters and boilers which went through t/a during the prior calendar year;
- (b.) The type of burner upgrade that was conducted on each heater and boiler;
- (c.) The results of all emission tests conducted on each heater and boiler identified in Paragraph 7 during the prior calendar year;
- (d.) A summary of the designed emission factors and results of all tested next generation burner technology

installations identified in Paragraph 7 conducted during the prior calendar year;

(e.) A summary of all heaters and boilers scheduled for t/a during the next calendar year and the dates of the scheduled t/a, and the type of technology that Koch expects to install on those units;

(f.) An identification of established permit limits (in lbs NO_x per mmBTU (HHV) fired) applicable to each heater or boiler modified under this Consent Decree;

(g.) A demonstration that the requirements of Paragraphs 14 and 17, if applicable, continue to be met with updates for changes to the initial plan as required by Paragraph 10; and

(h.) A summary of all CEMS and parametric monitoring installations during the prior calendar year.

B. NO_x Emission Reductions from FCCUs

Program Summary: Koch will demonstrate the use of low-NO_x combustion promoter and NO_x adsorbing catalyst additive at the Corpus Christi West FCCU, alone (catalyst test) and in combination with the implementation of Selective Non-Catalytic Reduction ("SNCR") for the reduction and control of NO_x emissions (combined technology test). Successful demonstrations will obligate Koch to implement the catalyst additives alone, SNCR alone, or the combined technologies at its two remaining refineries or to implement other technologies giving equivalent or superior emissions performance.

23. Prior to June 1, 2001, Koch shall begin the use of low-NO_x combustion promoter, alone and in combination with NO_x adsorbing catalyst additive in the Corpus West Plant's FCCU. The test for low NO_x combustion promoter will test the effect of complete replacement of conventional combustion promoter

with low NO_x combustion promoter wherever and whenever combustor promoter is used. Koch shall also attempt to use NO_x adsorbing catalyst additive alone, in an effort to quantify the emission reducing effects of each.

24. No later than December 31, 2001, Koch shall complete a study of the individual and combined effects of the additives on NO_x emissions from the FCCU, identify the amount of each catalyst additive, and the combined catalyst additives, and recommend to EPA the proposed economically reasonable maximum percentage of NO_x adsorbing catalyst additive up to 2% of total catalyst makeup, the addition of which results in the lowest feasible NO_x concentration in the regenerator flue gas at the tested facility.

25. Koch's proposal shall be included in a final report to EPA, "Catalyst Additive Study for Reduction of FCCU NO_x Emissions," to be submitted no later than March 31, 2002. EPA will provide a written response to Koch's proposal within 90 days.

26. During the planned shutdown of the Corpus Christi West FCCU, in calendar year 2002, Koch shall install an SNCR system which will allow the injection of a reductant, such as ammonia or urea, into the regenerator flue gas. Koch will

design the system to reduce emissions of NO_x from the FCCU regenerator as much as economically feasible.

27. Koch will not be required to install SNCR pursuant to Paragraph 26 if Koch is able to achieve a NO_x concentration of 20 ppmvd (at 0% oxygen) or less on an annual average basis using only catalyst additives. Alternatively, if Koch can achieve a 20 ppmvd (at 0% oxygen) concentration or lower with an emission reduction technology not specified in this Consent Decree, Koch may install an alternative technology that will meet the 20 ppmvd (at 0% oxygen) NO_x emission limit.

28. Koch may elect to change the location of the combined technology test from Corpus Christi West to the Pine Bend FCCU at its next t/a but no later than 2003, by providing written notice to EPA by December 31, 2001. If Koch elects to demonstrate the combined NO_x control technology at Pine Bend, all the requirements of this Section shall apply, with the exception that the completion date shall be extended to December 31, 2003.

29. Koch shall operate the SNCR system in conjunction with the combination of low-NO_x combustion promoter and NO_x eliminating catalyst additive that will yield the lowest feasible NO_x concentration in the FCCU regenerator flue gas, as supported by the study. Koch will operate this "combined

technology system" in an effort to achieve a NO_x concentration of 20 ppmvd at 0% oxygen. During the combined technology test, Koch will monitor SNCR inlet NO_x concentrations on a continuous basis for the period of the optimization study unless Koch shall propose and EPA shall approve an alternative monitoring frequency.

30. Koch will report the results of the combined technology test as follows:

(a.) Six months following the startup of the combined technology system, Koch will evaluate the success of this system based on the actual hourly, daily, weekly and projected annual average NO_x concentration in the regenerator flue gas using the CEMS and/or performance tests and will report this information to EPA within 8 months of startup.

(b.) One year following the startup of the combined technology system, Koch will evaluate the success of this system based on the actual hourly, daily, weekly, and annual average NO_x concentration in the regenerator flue gas using CEMS and/or performance tests, and will report this information to EPA within 15 months of startup.

For each report, Koch will prepare a summary for general use by the EPA and the States of Minnesota and Texas, notwithstanding any confidentiality claim by Koch.

31. For purposes of this Consent Decree, a "successful" test of the combined technology will be an annual average NO_x concentration of less than or equal to 20 ppmvd (at 0% oxygen).

32. For purposes of this Consent Decree, a "partially successful" test of the combined technology will be an annual average NO_x concentrations of less than 70 ppmvd (at 0% oxygen) but greater than 20 ppmvd (at 0% oxygen).

33. For purposes of this Consent Decree, a "partial failure" of the combined technology will be an annual average of daily NO_x concentrations of less than or equal to 100 ppmvd (at 0% oxygen), but greater than or equal to 70 ppmvd (at 0% oxygen).

34. For purposes of this Consent Decree, a "failure" of the combined technology will be an annual average NO_x concentration of greater than 100 ppmvd (at 0% oxygen).

35. Pursuant to this Consent Decree, success or partial success, as defined above, will compel Koch to do the following:

(a.) 3 months after submittal of final test report, begin using catalyst additives, where justified by the catalyst additive study in Paragraph 25, at Corpus Christi East and Pine Bend FCCUs;

(b.) During the next turnaround for each FCCU that occurs no sooner than 18 months after submittal of the 6-month test report, install SNCR at the Pine Bend FCCU and SNCR, using an enhanced reductant such as hydrogen, at the Corpus Christi East FCCU;

(c.) SNCR will not be required at the Corpus Christi East FCCU if Koch can achieve and demonstrate an annual average of daily NO_x concentrations less than or equal to 35 ppmvd (at 0% oxygen), and show that SNCR cost

effectiveness is greater than \$10,000 per ton (based on annualized cost); and

(d.) SNCR will not be required for any FCCU that demonstrates annual average concentration of less than or equal to 20 ppmvd (at 0% oxygen) NO_x without it.

36. Pursuant to this Consent Decree, partial failure in the combined technology test will compel Koch to propose an alternative for installation during the next t/a for that unit that is at least 18 months after the test report submission required by Paragraph 30(a). Such proposal will be approved if EPA determines that the alternate technology will achieve an annual average of daily NO_x concentrations of less than or equal to 70 ppmvd (at 0% oxygen). EPA shall provide a response to Koch within 90 days of submission.

37. Pursuant to this Consent Decree, failure in the combined technology test will compel Koch to propose an alternative control technology for all three FCCUs for installation during the next t/a for that unit that is at least 18 months after the test report submission required by Paragraph 30(a). Such proposal will be approved if EPA determines that the alternate technology will achieve an annual average of daily NO_x concentrations of less than or equal to 70 ppmvd (at 0% oxygen). EPA shall provide a response to Koch within 90 days of submission.

38. After the installation and startup of the combined technology or alternative technology, EPA and Koch, in consultation with the appropriate state agency, will determine the individual NO_x concentration limits for the Corpus Christi West, Corpus Christi East, and Pine Bend FCCUs, based on the level of demonstrated performance, process variability, reasonable certainty of compliance, and any other available pertinent information.

C. SO₂ Emission Reductions from FCCUs

Program Summary: Koch shall install advanced pollution control technology for the control of SO₂ emissions from its FCCU unit at Pine Bend, and will comply with interim limits for the reduction of SO₂ emissions until the control technology is implemented. Koch will also perform optimization studies for the wet gas scrubbers at the FCCUs at the Corpus Christi West and East refineries, and limit SO₂ emissions from those units consistent with the results of the study.

39. No later than the end of the next scheduled t/a in 2003 of the Pine Bend FCCU, Koch shall reduce SO₂ emissions from the Pine Bend FCCU and achieve an SO₂ concentration of 25 ppmvd (at 0% oxygen) on an annual average basis. Koch shall also meet a limit of 50 ppmvd (at 0% oxygen) on a 7-day average identical to the averaging period used in NSPS Subpart J. Koch may elect any means for attaining these reductions.

40. If Koch is unable to install equipment, or make the changes necessary to achieve the annual average of 25 ppmvd (at 0% oxygen) level of SO₂ reduction during the next scheduled t/a for the Pine Bend FCCU in 2003, then Koch shall meet this limit by the end of 2007, and shall meet interim SO₂ limits of 100 ppmvd (at 0% oxygen) in the flue gas on an annual average basis during the period between the next scheduled t/a and 2007.

41. Koch shall demonstrate compliance with either the 25 ppmvd (at 0% oxygen) or 100 ppmvd (at 0% oxygen) interim limits on a rolling annual average of daily SO₂ concentrations.

42. Koch shall demonstrate the reductions through continued operation of a CEMS for SO₂ on all 3 FCCUs.

43. No later than July 31, 2001, for the FCCUs at Corpus Christi West and East, and within one year of startup of the control technology at Pine Bend, Koch shall begin optimization studies on the existing Corpus Christi West and East FCCU wet gas scrubbers ("WGS") and the selected control technology at Pine Bend. Koch will submit a proposed protocol for the optimization studies to EPA for review and comment no later than 90 days prior to beginning the proposed study. The proposed protocol shall include, at a minimum (where

applicable): pH, scrubbing liquor circulation rate, liquid-to-gas ratio, where applicable, and propose for EPA approval the frequency for monitoring of WGS inlet SO₂ concentrations.

Koch shall submit to EPA a report on the optimization studies within 15 months of startup for Pine Bend and by October 31, 2002, for Corpus Christi East and West, and use the results of these optimization studies to propose to EPA new SO₂ concentration limits for the Corpus West, Corpus East, and Pine Bend FCCUs.

44. Koch will agree to reduce its SO₂ concentrations to levels demonstrated in each of the optimization studies, if the study supports that reductions are technologically feasible and not cost prohibitive. EPA, in consultation with Koch and the appropriate state agency, will determine the SO₂ concentration limits based on the level of demonstrated performance during the test period, process variability, reasonable certainty of compliance, and any other available pertinent information. For purposes of this Paragraph, the cost for further SO₂ reductions is prohibitive if it exceeds \$10,000 per ton of pollutant removed.

45. (A). Koch agrees that all of its heaters and boilers and all of its fluid catalytic cracking unit catalyst

regenerators are affected facilities for each pollutant regulated under NSPS Subpart J and subject to all of the applicable requirements of NSPS Subpart J, and will be in compliance for those units (heaters, boilers, and fluid catalytic cracking unit catalyst regenerators) by January 1, 2001, except as noted below:

(i) With regard to SO₂ emissions (H₂S inlet concentration) from heater 02BA201 at the Corpus Christi West Refinery and heater E0310F101 at the Corpus Christi East Refinery; opacity from the Corpus Christi West FCCU catalyst regenerator; and SO₂ emissions (H₂S inlet concentration) from heaters 27H-1 and 37H-3, 4, 5 at the Pine Bend Refinery, Koch has already submitted, or will submit by February 28, 2001, Alternative Monitoring Plan(s) ("AMP"), as specified in 40 C.F.R. § 60.13. If EPA approves an AMP, Koch will comply with Subpart J for that heater or FCCU within 6 months of such final approval, unless an earlier date is required by EPA. If EPA denies the AMP, Koch may elect to either: (a) install an H₂S analyzer within 18 months of the denial; or (b) submit a revised AMP within 6 months of the denial, unless EPA requires Koch to install an H₂S analyzer.

(ii) With regard to SO₂ emissions (H₂S inlet concentration) from heater E23H201A at the Corpus Christi East

Refinery; and boilers 17H2 and 17H4 at the Pine Bend Refinery, Koch will be in full compliance with Subpart J by December 31, 2003.

45. (B). Koch will continue to calibrate, maintain and operate SO₂, NO_x, CO and O₂ CEMS to continuously monitor air emissions from the Corpus Christi East and West, and Pine Bend FCCUs.

45. (C) All CEMS installed and operated pursuant to this agreement will be calibrated, maintained, and operated in accordance with the applicable requirements of 40 CFR §§ 60.11 and 60.13. These CEMS will be used to demonstrate compliance with emission limits pursuant to 40 CFR § 60.13(a) and shall be subject to the requirements of 40 CFR Part 60, Appendix F, with the following exception: Koch will not be required to conduct a Relative Accuracy Test Audit (RATA) once every four quarters, as specified in Sections 5.1.1 and 5.1.4 of Appendix F. Instead, a Cylinder Gas Audit (CGA) will be conducted each quarter. In addition, a Relative Accuracy Audit (RAA), as per Section 5.1.3 of Appendix F, shall be conducted (in lieu of a CGA) one quarter every three years. Koch may elect to conduct a RATA in lieu of this RAA.

D. Credit for Emissions Reductions

46. Except as specifically provided in this Section, Koch may not use any credits resulting from the emissions reductions required by this Consent Decree in any emissions banking, trading, or netting program for PSD, major non-attainment NSR, and minor NSR. The terms defined in this Section are for purposes of this Consent Decree only, and may not be used or relied upon by Koch or any other entity, including any party to this Consent Decree, for any other purpose, in any subsequent permitting action.

47. For purposes of this Section and the provisions of this Consent Decree only, "netting units" shall mean those sources specified below that have been or will be upgraded to the following control levels for the defined pollutants:

(a.) FCCU NO_x - The Corpus Christi East and West FCCUs and Pine Bend FCCU will be considered netting units for NO_x upon Koch's demonstration that the units have achieved emissions levels less than 70 ppmvd (at 0% oxygen) as required by Part IV, Section B of this Consent Decree;

(b.) FCCU SO₂ - The Corpus Christi East and West FCCUs are considered netting units for SO₂ at the time of lodging of this Consent Decree. The Pine Bend FCCU will be considered a netting unit for SO₂ upon Koch's demonstration that it has achieved the final SO₂ emission levels required by Part IV, Section C of this Consent Decree;

(c.) Sulfur Recovery Plants ("SRPs") - All SRPs at the Corpus Christi East, West, and Pine Bend refineries are

considered netting units at the time of lodging of this Consent Decree; and

(d.) Heaters and boilers - All heaters and boilers with a capacity smaller than 40 mmBTU/hr; all heaters and boilers with a capacity greater than or equal to 40 mmBTU/hr that are or will be equipped with current or next generation ULNB as defined in Part IV, Section A of this Consent Decree; all heaters and boilers with a capacity greater than or equal to 40 mmBTU/hr which are controlled to a level less than or equal to 0.045 lb NO_x/mmBTU (HHV) maximum allowable emissions are considered netting units upon their demonstration of compliance with the terms of this Consent Decree.

Units which have not met the definition of netting units may not use any credits generated under this Consent Decree.

48. All future heaters and boilers with next generation ULNB which are firing fuel gas meeting the NSPS Subpart J H2S limit of 0.1 gr/dscf. shall be defined as netting units for purposes of this Section.

49. Heaters and boilers with a capacity of greater than or equal to 40 mmBTU/hr that Koch upgrades with current generation ULNB but do not achieve an allowable NO_x emission rate of less than or equal to 0.045 lb/mmBTU (HHV) at full rates, as determined by the initial stack test with allowance made for operational factors, will be considered as a "try and fail" modification.

50. Koch may average these "try and fail" units in with the technologically infeasible group (see Paragraph 14), but

may not consider them as part of this group for purposes of the exemptions in Paragraphs 17 and 52, or Koch may submit a written request to EPA for a specific source netting unit determination pursuant to this Section.

51. Koch's request for a netting unit determination under this Section shall contain stack test data, an explanation of why the source was not able to accept an allowable NO_x emission rate of less than or equal to 0.045 lb NO_x/mmBTU (HHV), and a discussion of other control options considered. EPA shall consider efforts made by Koch to meet the 0.045 lb NO_x/mmBTU (HHV) level and provide a determination or request additional information within 90 calendar days from the date Koch's request is received. Upon EPA's written approval or if EPA has not requested additional information within 90 days, the source will be a netting unit for purposes of this Section.

52. Koch may designate up to three (3) heaters and boilers at Pine Bend, and three (3) heaters and boilers in the combined Corpus Christi East and West refineries which fall into the "technologically infeasible" category as netting units under this Section.

E. Emission Credit Generation and Classification

Program Summary: The emissions credit and netting limitations discussed below only apply to the netting units defined in this Section, and only to NO_x and SO₂ emissions. All other emission sources of NO_x and SO₂, and any netting associated with other pollutants, are outside the scope of these netting limitations and are subject to PSD/NSR applicability as implemented by the appropriate permitting authority or EPA. Emission reductions subject to this revised netting policy are only those reductions generated by installation of controls on sources defined as netting units in Section D and those reductions discussed further in Part IX. The provisions of this Section are for purposes of this Consent Decree only, and may not be used or relied upon by Koch or any other entity, including any party to this Consent Decree, for any other purpose, in any subsequent permitting or enforcement action.

53. For purposes of this Section, "emission reductions" are defined as the difference between the previous 2-year actual emissions or another more representative 2-year period (as defined pursuant to 40 C.F.R. § 52.21) and the future allowable emissions, as determined by the state permitting authority, after installation of controls.

54. Emission reductions generated by Koch, pursuant to this Consent Decree, will be allocated into two categories for future netting credit, "actual credits" and "allowable credits." The allocation of the emission reductions will be based on the source type and emission level achieved as described below. Emissions reductions from changes made by

Koch that are not required by this Consent Decree can be used for netting as described in 40 C.F.R. § 52.21 and as otherwise allowed under any applicable state or local regulation.

55. Use of credits generated through changes to, or the shutdown of, Pine Bend heaters 11H-3, 11H-4, 11H-5, 12H-4 and 16H-1 will not be restricted under this decree.

56. Emission reductions generated by Koch at heaters and boilers firing more than 40 mmBTU/hr(HHV) by the installation of netting unit controls, by completion of certain of the pollution reduction projects discussed in Paragraph 110, by permanent shutdown, or by installation of other controls are subject to the following allocations:

(a.) For SO₂ reductions by limiting fuel oil firing at the Pine Bend refinery to 100,000 barrels per calendar year (see Paragraph 110), as reflected in accepted federally enforceable requirements, Koch shall receive 90% actual credits and 10% allowable credits;

(b.) For NO_x reductions to a level of less than or equal to 0.045 lb NO_x/mmBTU (HHV) on a 3 hour average basis at a maximum firing duty, as determined through accepted federally enforceable limits, Koch shall receive 90% actual credits and 10% allowable credits; and

(c.) For NO_x reductions to a level of less than or equal to 0.02 lb NO_x/mmBTU (HHV) on a 3 hour average basis at maximum firing duty (including permanent shutdown of sources) as determined through federally enforceable limits, Koch shall receive 80% actual credits and 20% allowable credits.

57. Emission reductions generated by Koch at FCCU's by meeting the netting unit definition in Section D above, are subject to the following allocations:

(a.) For SO₂ reductions to a level of less than or equal to 25 ppmvd (at 0% oxygen) on an annual average basis, Koch shall receive 90% actual credits and 10% allowable credits;

(b.) For NO_x reductions to a level of less than or equal to 70 ppmvd (at 0% oxygen) on an annual average basis, Koch shall receive 75% actual credits and 25% allowable credits; and

(c.) For NO_x reductions to a level of less than or equal to 20 ppmvd (at 0% oxygen) on an annual average basis, Koch shall receive 50% actual credits and 50% allowable credits.

58. Koch may use the emission reductions generated by control of sources to the netting unit levels for PSD netting purposes at sources already classified as netting units or sources eligible for netting unit classification, consistent with the netting unit definitions in Part IV, Section D. Koch must make the emissions reductions federally enforceable through then existing mechanisms. Emissions reductions are creditable for 5 years from the date of generation and shall survive the termination of the Consent Decree.

59. For purposes of this Consent Decree, "allowable credits" generated can be used for PSD netting associated with netting units or sources that will later become netting units

as defined and identified in this Consent Decree. Allowable credits can be used in netting calculations without restriction, except that credits may not be used to increase the concentration of the pollutant over agreed-upon levels, i.e., can increase FCCU throughput, air burn, tons/year of SO₂, but cannot use credits to relax the 25 ppmvd (at 0% oxygen) limit to say, 30 ppmvd (at 0% oxygen). Allowable credits can be used for netting units, including: (a) sources increasing their potential-to-emit (PTE); (b) sources with no increase in PTE but with an actual emissions increase; (c) construction of netting unit replacement sources; and (d) construction of netting unit new sources, where both replacement sources and new sources meet the criteria established in Paragraph 47.

60. For purposes of this Consent Decree, where allowable credits are used on heaters or boilers that are increasing their potential to emit SO₂ or NO_x, but have not yet been upgraded to a netting unit, those sources are required to be upgraded to ULNB or an alternate emission reduction technology providing that those units will achieve a NO_x emission rate of less than or equal to 0.045 lb NO_x/mmBTU (HHV), by the time lines specified in Part IV, Section A of this Consent Decree.

61. For purposes of this Consent Decree, "actual credits" generated by Koch can be used for PSD netting associated with netting units or sources that will later become netting units as defined and identified in Part IV, Section D of this Consent Decree. Koch may only use actual credits in netting calculations for those sources with no increase in potential to emit but with an actual emissions increase (as defined pursuant to 40 C.F.R. § 52.21). Where actual credits are used on heaters or boilers that are increasing their actual emissions but have not yet been upgraded to a netting unit, those sources are required to be upgraded to ULNB or an alternate emission reduction technology that will achieve a NO_x emission rate of less than 0.045 lb NO_x/mmBTU (HHV), by the timelines specified in Part IV, Section A of this Consent Decree.

62. Where allowable emissions or federally enforceable limits are referred to in this Consent Decree: (a) for heaters and boilers without CEMS, these limits will be determined as the average of three one-hour stack test runs; (b) for heaters and boilers with CEMS, these limits will be determined on a 3-hour rolling average basis; and (c) for FCCUs, these limits

will be determined on an annual average basis, except where otherwise specified in this Consent Decree.

V. PROGRAM ENHANCEMENTS RE: BENZENE WASTE NESHAAP

Program Summary: Koch agrees to undertake the following measures to minimize or eliminate fugitive benzene waste emissions at its refineries. Unless otherwise stated, all actions will commence on January 1, 2001.

63. In addition to the provisions set forth below, the Corpus Christi West and Pine Bend refineries shall continue to comply with the compliance option set forth at 40 C.F.R. § 61.342(c), utilizing the exemptions set forth in 40 C.F.R. § 61.342(c)(2) and (c)(3)(ii) ("2Mg compliance option"), and the Corpus Christi East refinery shall continue to comply with the compliance option set forth at 40 C.F.R. § 61.342(e) ("6BQ compliance option"). Koch agrees that during the life of the Consent Decree, its Corpus Christi East refinery will not switch to the 2Mg compliance option. The Corpus Christi West and Pine Bend refineries may switch to the 6BQ compliance option by providing notice of this intent prior to the start of the calendar year.

64. Koch will conduct audits of all the laboratories that perform analysis of its benzene waste NESHAAP samples to ensure that proper analytical and quality assurance procedures

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are followed. By July 1, 2001, Koch will conduct the audits of the laboratories used by one of its refineries, and will complete audits for the remaining two refineries by December 31, 2001. Koch shall conduct subsequent laboratory audits every 2 years, or prior to using a new lab for benzene analysis, during the life of this Consent Decree.

65. Koch shall continue its annual program of reviewing process information, including but not limited to construction projects, to ensure that all benzene waste streams are included in each refinery's inventory.

66. Beginning January 1, 2001, Koch will conduct quarterly sampling and analysis of the following uncontrolled benzene waste streams:

(a.) For refineries complying with the 6BQ compliance option, all uncontrolled waste streams that contributed greater than 0.03 Mg to the previous year's TAB calculation shall be sampled once per calendar quarter, with at least 30 days between samples;

(b.) For refineries complying with the 2Mg compliance option, all uncontrolled waste streams that contributed greater than 0.1 Mg to the previous year's TAB calculation and that qualify for the exemption under 40 C.F.R. § 61.342(c)(2) shall be sampled once per calendar quarter, with at least 30 days between samples; and

(c.) For refineries complying with the 2Mg compliance option, all uncontrolled waste streams, other than those qualifying for the exemption found in 40 C.F.R. § 61.342(c)(2), that contributed greater than 0.03 Mg to

the previous year's TAB calculation shall be sampled once per calendar quarter, with at least 30 days between samples.

67. Beginning with the first full calendar year following lodging of this Consent Decree, Koch shall verify annually in the report required to be submitted under 40 C.F.R. § 61.357(d)(2) whether there has been a change in the control status of all of the following types of waste streams:

- (a.) Slop oil;
- (b.) Tank water draws;
- (c.) Spent caustic;
- (d.) Desalter rag layer dumps;
- (e.) Desalter vessel process sampling points; and
- (f.) Other sample wastes.

68. Koch shall comply with the following measures at all locations where carbon canisters are utilized as a regulated control device under the Benzene Waste NESHAP.

(a.) By December 31, 2001, Koch shall install primary and secondary carbon canisters and operate them in series;

(b.) Koch shall continue to measure breakthrough at times when the source is connected to the carbon canister, and during periods of normal operation in accordance with the frequency specified in 40 C.F.R. § 61.354(d);

(c.) For a single canister system, breakthrough shall be defined as a condition where the outlet of the canister is >100 ppmv VOC or >20 ppmv benzene, and the canister is providing a reduction of <98% VOC or <99% benzene. For a primary and secondary canister system, breakthrough shall be defined as a condition where the outlet of the primary canister is >100 ppmv VOC or >20 ppmv benzene, and the

primary canister is providing a reduction of <95% VOC or <98% benzene; and

(d.) Koch shall replace existing carbon with fresh carbon immediately when carbon breakthrough is detected, in accordance with 40 C.F.R. § 61.354(d). Immediately shall be considered as within 24 hours upon determination of breakthrough for a primary and secondary canister system and within 8 hours for a single canister system.

69. Koch shall continue to review all spills within the refinery to determine if benzene waste was generated. Koch shall continue to account for all benzene wastes generated through spills that are not managed solely in controlled waste management units in its annual calculation against the 6 BQ or 2 Mg compliance option as applicable.

70. Koch shall continue to manage all groundwater remediation conveyance systems in accordance with the applicable control requirements of the Benzene Waste NESHAP.

71. Beginning with the first full calendar quarter commencing January 1, 2001, Koch shall implement the following compliance measures at all refineries:

(a.) Koch shall conduct monthly visual inspections of all water traps within its individual drain systems that are subject to the Benzene Waste NESHAP;

(b.) Koch shall continue to control all slop oil recovered from its oil/water separators, sewer systems, etc., until recycled or put into a feed tank, if not already counted toward the uncontrolled total;

(c.) Koch shall develop and implement training for all technicians required to take benzene waste samples;

(d.) Koch shall continue to provide the person(s) within each refinery responsible for overseeing the benzene waste program access to real-time benzene waste process monitoring information related to control equipment;

(e.) Koch shall continue to make real-time benzene waste process monitoring information related to control equipment available electronically to the operator(s) responsible for benzene waste systems in each refinery; and

(f.) Koch shall identify/mark all area drains that are segregated stormwater drains by December 31, 2001.

72. By December 31, 2001, Koch shall evaluate each of the following projects at each refinery, including, but not limited to, each project's feasibility (including estimated costs, where appropriate):

(a.) Installation of closed loop sampling devices on all waste and process streams that are greater than 10 ppmw benzene;

(b.) Installation of new Benzene Waste NESHAP waste sample points at all locations where routine sampling points are not easily accessible; and

(c.) Implementation of the 6 BQ option, which allows for more straight forward, end of the line sampling, at the Corpus Christi West and Pine Bend refineries, for demonstrating compliance with the Benzene Waste NESHAP.

Recordkeeping and Reporting Requirements for Part V

73. As part of the overall progress reports submitted pursuant to Part XI (General Recordkeeping and Reporting), Koch shall include the following information:

(a.) with respect to the initial lab audits, Koch shall include information listing the steps it has taken to implement Paragraph 64 (initial lab audits). After completion of the initial lab audits, Koch's final progress report on this requirement shall include any corrective actions taken as a result of each audit;

(b.) With respect to carbon canister installation, Koch shall include information listing the steps it has taken to implement Paragraph 68(a) (carbon canister installation). After installation of the carbon canisters is complete, Koch's final progress report on this requirement shall include a listing of all locations within the refinery where secondary canisters were placed in service;

(c.) in its first progress report after the first quarter of 2001, Koch shall submit a certification that the training program required by Paragraph 71(c) has been developed and initiated; and

(d.) in its first progress report filed after completing each project evaluation required by Paragraph 72, Koch shall summarize the results of the evaluations, any future plans for action, including, at a minimum, the feasibility of each project, and any reasons why Koch may have elected not to proceed with the project.

74. Beginning with the first full calendar quarter commencing January 1, 2001, Koch shall submit to the appropriate state and EPA office, the following information

for each of its refineries as part of the report required by
40 C.F.R. § 61.357(d)(7):

(a.) The results of the quarterly sampling conducted pursuant to Paragraphs 66(a) through 66(c), above, if sampling results are available. If certain sampling results are not available prior to submitting the report for that quarter, such results shall be submitted with the next quarter's report;

(b.) Koch shall use the quarterly sampling results pursuant to Paragraph 66 and the previous year's annual report (for unsampled waste streams) to estimate projected quarterly and calendar year values against the 6BQ or 2Mg compliance option;

(c.) If the estimated quarterly calculation for any refinery made pursuant to Paragraph 74(b), above, exceeds 0.5 Mg for refineries complying with the 2 Mg compliance option or 1.5 Mg for refineries complying with the 6 BQ compliance option, or if the projected annual calculation for any refinery made pursuant to this Paragraph exceeds 2 Mg for refineries complying with the 2 Mg compliance option, or 6 Mg for refineries complying with the 6 BQ compliance option, Koch shall include a summary of the activities planned to minimize benzene wastes at the refinery, or a discussion of why no activity is necessary to ensure that the calendar year calculation complies with the Benzene Waste NESHA. For purposes of this subParagraph, Koch will use best available data, but may have better information available when it submits the annual reports required by 40 C.F.R. § 61.357(d)(2); and

(d.) Koch shall identify all labs used during the quarter for analysis of benzene waste samples and identify when Koch's most recent audit of each lab occurred.

VI. PROGRAM ENHANCEMENTS RE: LEAK DETECTION AND REPAIR

Program Summary: Koch agrees to undertake the following measures regarding leak detection and repair ("LDAR") at its refineries in accordance with the following schedule. Unless

otherwise stated, the Corpus Christi East and West refineries will be considered as one LDAR program for purposes of this Agreement. Unless otherwise stated, all actions will commence on January 1, 2001.

75. By no later than December 31, 2001, Koch shall develop a written refinery-wide program for LDAR compliance for each refinery. These programs shall include, at a minimum: an overall refinery-wide leak rate goal (to be applied unit-by-unit), procedures for identifying leaking components, and procedures for identifying and including new components in the LDAR program. As set forth below, certain elements of the program will be enforceable by EPA, and Koch will implement other management-type elements on an enforceable schedule, but the elements themselves will not be enforceable against Koch under the terms of this Consent Decree. Koch will implement this program according to the schedules specified in the Paragraphs below.

76. By no later than December 31, 2002, Koch's LDAR programs shall be implemented refinery-wide, including all components within all areas that are owned and maintained by the refineries. As referenced in this Section, "components" shall mean applicable regulated equipment as defined in 40

C.F.R. Part 60, subpart VV, and 40 C.F.R. Part 63, subparts H and CC, excluding the definition of "process unit."

77. By no later than December 31, 2001, Koch shall develop and begin implementing the following training programs at each refinery:

(a.) For new LDAR personnel, Koch shall provide and require LDAR training prior to the employee beginning work in the LDAR group;

(b.) For all LDAR personnel, Koch shall provide and require completion of annual LDAR training; and

(c.) For all other refinery operations personnel, Koch shall provide and require annual review courses for LDAR monitoring.

78. Koch shall implement the following audit programs (the Corpus Christi refineries will be audited as one LDAR program) focusing on comparative monitoring, records review and observation of the LDAR technicians' actual calibration and monitoring techniques:

(a.) Koch shall conduct biennial internal audits of each refinery's LDAR program. These audits will be conducted by sending representative LDAR personnel from one Koch refinery to the other. One refinery will have its first audit during the first full calendar year after the Consent Decree is lodged. The other refinery will conduct its first audit no later than the following calendar year; and

(b.) Koch agrees to have a third party audit each refinery's LDAR program at least twice during the overall life of the Consent Decree.

79. By December 31, 2002, Koch shall implement an internal leak definition of 500 ppmv for all valves, and 2000 ppmv for all pumps. Koch may continue to report leak rates against the regulatory leak definition, or may elect to use the lower leak rate definition for reporting purposes.

80. Beginning January 1, 2001, Koch shall require LDAR personnel to make a "first attempt" at repairing any valve that has a reading above 50 ppmv, excluding control valves and other components that LDAR personnel are not authorized to repair. Koch will only record, track and remonitor leaks above Koch's internal leak definition.

81. Koch shall implement a program of more frequent monitoring by December 31, 2002, for all valves by choosing one of the following options on a process unit by process unit basis:

(a.) Quarterly monitoring with no ability to skip periods. This option cannot be chosen for process units subject to the HON or the modified-HON option in the Refinery MACT;

(b.) Implementation of a Sustainable Skip Period Program as set forth in Attachment 1 to this Consent Decree;

(c.) Units that have already utilized a skip leak interval with a leak definition as listed in Paragraph 79, are not required to return to a more frequent monitoring interval upon application of the Sustainable Skip Period Program as of December 31, 2002, but shall immediately be subject to the requirements of the program on a going forward basis; and

(d.) Units that have not utilized the 500 ppmv leak definition prior to December 31, 2002, shall enter the program on a quarterly frequency, unless their current interval is shorter.

82. For process units complying with the Sustainable Skip Period Program in Attachment 1, Koch shall use the leak rate determined during an EPA or State inspection to require more frequent monitoring, if appropriate. Koch will utilize the more frequent monitoring program beginning at the start of the next calendar month, provided that if Koch is obligated under applicable regulations to complete its monitoring program for the prior monitoring period and if additional time is required to make the transition, EPA and Koch will agree on a later date to move to the more frequent period. The leak rate determination during EPA or state inspections shall be made based on the total number of leaking valves identified during the inspection divided by the total number of valves in the process unit that Koch uses

to determine the leak rates, rather than the total number of valves monitored during the inspection.

83. Beginning July 1, 2001, Koch shall use dataloggers and/or electronic data storage for LDAR monitoring. Koch can use paper logs where necessary or more feasible (i.e. small rounds, remonitoring when dataloggers are not available or broken, inclement weather, etc).

84. By December 31, 2001, Koch shall have developed standards for new equipment (i.e., pumps, relief valves, sample connections, other valves) it is installing to minimize potential leaks. Koch will also make use of improved equipment, such as "leakless" valves for chronic leakers, where available, technically feasible, and economically reasonable.

85. If, during the life of this Consent Decree, Koch ~~completely~~ subcontracts its LDAR program at any of its refineries, Koch shall require its LDAR contractors to conduct a QA/QC review of all data before turning it over to Koch and to provide Koch with daily reports of its monitoring activity.

86. By December 31, 2001, Koch shall have established a program that will hold LDAR personnel accountable for the

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quality of monitoring and an overall refinery program to provide incentives for leak rate improvements.

87. Koch shall continue to maintain a position within the refinery (or under contract) responsible for LDAR coordination, with the authority to implement these and other recommended improvements.

88. By December 31, 2001, Koch shall have established a tracking program for maintenance records to ensure that components added to the refinery during maintenance and/or construction are added to the LDAR program.

89. Koch shall have the option of monitoring all components within a process unit within 30 days after the startup of the process unit after the turnaround without having the results of the monitoring used in the leak rate determination. Process unit t/a's are considered those activities that are planned on a typical 2-4 year cycle that require a complete unit shutdown.

90. Beginning January 1, 2001, Koch will conduct calibration drift assessments of the LDAR monitoring equipment in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21 at the end of each monitoring shift, at a minimum. Koch agrees that if any calibration drift

assessment after the initial calibration shows a negative drift of more than 10%, it will remonitor all components since the last calibration that had readings above 50 ppmv.

91. Beginning the first calendar quarter following lodging of this Consent Decree, but no sooner than January 1, 2001, for valves that meet the regulatory requirements to be put on the "delay of repair" list for repair,

(a.) Koch shall require sign-off by the PL (unit foreman) or equivalent or higher authority before the component is eligible for the "delay of repair" list;

(b.) Koch shall set a leak level of 50,000 ppmv at which it will undertake "heroic" efforts to fix the leak rather than put the valve on the "delay of repair" list, unless there is a safety or major environmental concern posed by repairing the leak in this manner. For valves, heroic efforts/repairs shall be defined as non-routine repair methods, such as the drill and tap;

(c.) Koch shall include valves that are placed on the "delay of repair" list in its regular LDAR monitoring, and make "heroic" repair efforts, unless there is a safety or major environmental concern posed by repairing the leak in this manner, if leak reaches 50,000 ppmv; and

(d.) After April 1, 2001, Koch shall undertake heroic efforts to repair valves that have been on the "delay of repair" list for a period of longer than 36 months, unless there is a safety or major environmental concern posed by repairing the leak in this manner.

Recordkeeping and Reporting Requirements For Part VI

92. As part of the progress report submitted pursuant to Part XI, Koch shall submit the following information:

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(a.) As part of the first progress report required to be submitted after December 31, 2001, Koch shall include a copy of the written LDAR program for each refinery developed pursuant to Paragraph 75;

(b.) In the first progress report due after the training program required by Paragraph 77 has been implemented at each refinery, Koch shall submit a certification that the training has been implemented;

(c.) In its first progress report due under this Consent Decree, Koch shall submit a certification that the first attempt repair program as described in Paragraph 80 has been implemented;

(d.) As part of the first progress report required to be submitted after July 1, 2001, Koch shall submit a status report on the use of dataloggers and/or electronic data storage for data monitoring as required by Paragraph 83;

(e.) In the first progress report submitted after December 31, 2001, Koch shall include a description of the equipment standards developed pursuant to Paragraph 84;

(f.) As part of the first progress report submitted after December 31, 2001, Koch shall include a description of the accountability/incentive programs that are developed pursuant to Paragraph 86;

(g.) As part of the first progress report submitted after December 31, 2001, Koch shall include a description of the maintenance tracking program developed pursuant to Paragraph 88;

(h.) As part of its first progress report required by this Consent Decree, Koch shall submit a certification that it has implemented the calibration drift assessments described in Paragraph 90; and

(i.) As part of its first progress report required by this Consent Decree, Koch shall include a certification

that it has implemented the "delay of repair" requirements described in Paragraph 91.

93. Koch shall maintain the audit results from Paragraph 78 and any corrective action implemented. The audit results shall be made available to the EPA and State authorities upon request.

94. As part of the semiannual monitoring reports required by 40 C.F.R. Part 63, Subparts H or CC, Koch shall provide a listing of those units that became subject to the program described in Paragraph 81 during the reporting interval. This report shall include the projected date of the next monitoring frequency for each process unit.

VII. PROGRAM ENHANCEMENTS RE: NSPS SUBPARTS A AND J
SULFUR DIOXIDE EMISSIONS FROM SULFUR RECOVERY PLANTS
("SRP") AND FLARING DEVICES

PROGRAM SUMMARY: Upon the lodging of this Consent Decree, Koch agrees to take the following measures, identified in this Section at all five of its Claus SRPs and certain flaring devices at its 3 refineries. Koch is committed to the goal of eliminating all reasonably preventable SO₂ emissions from flaring. Koch has taken a number of effective steps to reduce the frequency and duration of Flaring Incidents and to improve the refineries' sulfur recovery performance. Koch is also committed to extending the duration between SRP unscheduled and scheduled maintenance shutdowns to three years or greater.

95. DEFINITIONS: Unless otherwise expressly provided herein, terms used in this Part shall have the meaning given

to those terms in the Clean Air Act, 42 U.S.C. §§ 7401 et seq., and the regulations promulgated thereunder. In addition, the following definitions shall apply to the terms contained within Part VII of this Consent Decree:

(a.) "Acid Gas" shall mean any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of an amine scrubber solution;

(b.) "AG Flaring" shall mean, for purposes of this Consent Decree, the combustion of Acid Gas and/or Sour Water Stripper Gas in a Flaring Device. Nothing in this definition shall be construed to modify, limit, or affect EPA's authority to regulate the flaring of gases that do not fall within the definitions contained in this Decree of Acid Gas or Sour Water Stripper Gas;

(c.) "AG Flaring Device" shall mean any device at the Refinery that is used for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The combustion of Acid Gas and/or Sour Water Stripper Gas occurs at the following locations:

- (i) Pine Bend - one dedicated sour water stripper gas flare and the refinery main flare system
- (ii) Corpus Christi West - acid gas flare
- (iii) Corpus Christi East - acid gas flare

To the extent that the refinery utilizes Flaring Devices other than those specified herein for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, those Flaring Devices shall be covered under this Decree.

(d.) "AG Flaring Incident" shall mean the continuous or intermittent flaring/combustion of Acid Gas and/or Sour Water Stripper Gas that results in the emission of sulfur dioxide equal to, or greater than five-hundred (500) pounds in a twenty-four (24) hour period; provided, however, that if five-hundred (500) pounds or more of

sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the AG Flaring Incident.

(e.) "Day" shall mean a calendar day.

(f.) "Hydrocarbon Flaring" shall mean, for purposes of this Consent Decree, the combustion of refinery process gases, except for Acid Gas, Sour Water Stripper Gas, and/or Tail Gas, in a Hydrocarbon Flaring Device. Nothing in this definition shall be construed to modify, limit, or affect EPA's authority to regulate the flaring of gases that do not fall within the definitions contained in this Decree.

(g.) "Hydrocarbon Flaring Device" shall mean a flare device used to safely control (through combustion) any excess volume of a refinery process gas other than Acid Gas, Sour Water Stripper Gas, and/or Tail Gas. The subject Hydrocarbon Flaring Devices are:

- (i) Pine Bend - the refinery main flare system
- (ii) Corpus Christi West - the refinery main flare system
- (iii) Corpus Christi East - 36" Flare

To the extent that a refinery utilizes Flaring Devices that are functionally equivalent and are in the same service as those specified above, those Flaring Devices shall be covered under this Decree.

(h.) "Hydrocarbon Flaring Incident" shall mean the continuous or intermittent flaring of refinery process gases, except for Acid Gas, Sour Water Stripper Gas, or Tail Gas, at a Hydrocarbon Flaring Device equipped with a flare gas recovery system, that results in the emissions of sulfur dioxide equal to, or greater than five-hundred

(500) pounds in a twenty-four (24) hour period (the 500 pound sulfur dioxide trigger will be determined on the amount of sulfur dioxide emissions above the flare permitted emission limit); provided, however, that if five-hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non-overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one Hydrocarbon Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the Hydrocarbon Flaring Incident.

(i.) "Malfunction" shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(j.) "Root Cause" shall mean the primary cause of an AG Flaring Incident, Hydrocarbon Flaring Incident, or a Tail Gas Incident, as determined through a process of investigation; provided, however, that if any such Incident encompasses multiple releases of sulfur dioxide, the "Root Cause" may encompass multiple primary causes.

(k.) "Scheduled Maintenance" of an SRP shall mean any shutdown of an SRP that Koch schedules at least ten (10) days in advance of the shutdown for the purpose of undertaking maintenance of that SRP.

(l.) "Shutdown" shall mean the cessation of operation of an affected facility for any purpose.

(m.) "Sour Water Stripper Gas" or "SWS Gas" shall mean the gas produced by the process of stripping or scrubbing refinery sour water.

(n.) "Startup" shall mean the setting in operation of an affected facility for any purpose.

(o.) "Sulfur Recovery Plant" shall mean the devices at Koch's Refinery identified as:

(i). Pine Bend: "Unit 45" (SRUs-3&4) and Unit 26 (SRU-5);

(ii). Corpus Christi West: "SRU#1" and "SRU#2";

(iii). Corpus Christi East, "East SRU".

(p.) "Tail Gas" shall mean exhaust gas from the Claus trains and/or the tail gas treating unit ("TGTU") section of the SRP;

(q.) "Tail Gas Incident" shall mean, for the purpose of this Consent Decree, combustion of Tail Gas that either:

i) is combusted in a flare and results in 500 pounds of sulfur dioxide emissions in a 24 hour period; or

ii) is combusted in a monitored incinerator and the amount of sulfur dioxide emissions in excess of the 250 ppm limit on a rolling twenty-four hour average exceeds 500 pounds.

(r.) "Upstream Process Units" shall mean all amine contactors, amine scrubbers, and sour water strippers at the refinery, as well as all process units at the refinery that produce gaseous or aqueous waste streams that are processed at amine contactors, amine scrubbers, or sour water strippers.

96. SRP NSPS SUBPART A and J APPLICABILITY:

(a.) With respect to all five of Koch's Claus Sulfur Recovery Plants at its three refineries, they are subject to and will continue to comply with the applicable provisions of NSPS Subpart A and J.

(b.) Koch agrees that all emission points (stacks) to the atmosphere for tail gas emissions from each of its Claus Sulfur Recovery Plants will continue to be monitored and

reported upon as required by 40 C.F.R. §§ 60.7(c), 60.13, and 60.105(a)(5). This requirement is not applicable to the AG Flaring Devices identified in Paragraph 95(c).

(c.) Koch will continue to route all SRP sulfur pit emissions such that they are monitored and included as part of the SRP's emissions that are compared to the NSPS Subpart J limit for SO₂, a 12-hour rolling average of 250 ppmvd SO₂ at 0% oxygen, as required by 40 C.F.R. § 60.104(a)(2).

(d.) Koch will continue to conduct SRP emissions monitoring with CEMS at all of the emission points unless a sulfur dioxide alternative monitoring procedure has been approved by EPA, per 40 C.F.R. § 60.13(i), for any or all of the emission points.

(e.) For the purpose of determining compliance with the SRP emission limits, Koch shall apply the start-up shutdown provisions set forth in NSPS Subpart A to the Claus Sulfur Recovery Plant and not to the independent start-up or shut-down of its corresponding control device(s) (e.g. TGTU). However, the malfunction exemption set forth in NSPS Subpart A does apply to both the Claus Sulfur Recovery Plant and its control device(s) (e.g., TGTU).

(f.) At Corpus Christi East, by December 31, 2003, Koch will ensure that the Sour Water Stripper Tank off-gas is either removed from the SRP incinerator or independently controlled and monitored to meet NSPS Subpart J emission limit at 40 C.F.R. §60.104(a)(1).

97. SULFUR RECOVERY PLANT OPTIMIZATION:

(a.) Koch stipulates that it has performed and will continue to perform system reliability and optimization studies, utilizing Reliability Centered Maintenance (RCM) protocols, on its SRP's at all three refineries. The RCM protocols are being used to optimize the performance of the Claus train for the actual characteristics of the feed to the SRP.

(b.) Koch has reviewed AG Flaring Incidents which occurred over the past four (4) years on a refinery by refinery basis. The information gained from these reviews was used to help ensure that the reliability studies focused on all known potential causes of AG Flaring due to the design, operation and maintenance of the SRPs, and to ensure that any historically identified corrective actions have been or will be implemented for addressing those causes.

(c.) Koch stipulates that it has performed a Root Cause Failure Analysis (RCFA) of the recent AG Flaring Incidents at all three refineries, identified causes of AG Flaring, and has implemented or is in the process of identifying and implementing corrective actions to minimize the number and duration of AG Flaring events attributable to problems within the SRP.

98. FLARING. By March 31, 2001, Koch shall, at the 3 refineries, implement procedures for evaluating whether future AG Flaring Incidents, Hydrocarbon Flaring Incidents, and Tail Gas Incidents are due to malfunctions. The procedures require root cause analysis and corrective action for all types of flaring and stipulated penalties for AG Flaring Incidents or Tail Gas Incidents if the root causes were not due to malfunctions.

99. HYDROCARBON FLARING. Koch and EPA stipulate for purposes of this Consent Decree that its main refinery flares at its 3 refineries are subject to NSPS Subpart J as fuel gas combustion devices in addition to being emergency control devices for quick and safe release of malfunction gases. Koch

and EPA also stipulate that the best way to ensure compliance with those flares' NSPS obligations is through implementation of good air pollution control practices for minimizing flaring activity, as required by 40 C.F.R. §60.11(d), and not through monitoring of compliance with 40 C.F.R.

§60.104(a)(1). EPA and the Minnesota Pollution Control Agency ("MPCA") agree that Koch's operation of its refineries in conformance with Koch's Flare Policy, Attachment 2, ensures that Hydrocarbon Flaring is not subject to the emission limitation, monitoring or other requirements for refinery fuel gas found in 40 C.F.R. §§ 60.100 - 60.109.

Koch shall implement the following additional mitigation measures:

(a.) For Hydrocarbon Flaring at Pine Bend and Corpus Christi West, Koch shall continue to operate and maintain the flare gas recovery systems and investigate, report and correct the cause of flaring in accordance with the procedures in Koch's Flare Policy, Attachment 2 to this Consent Decree.

(b.) For Hydrocarbon Flaring at Corpus Christi East, by December 31, 2003, Koch shall install a flare gas recovery system and then operate and maintain the flare gas recovery system. By January 7, 2004, Koch shall begin to investigate, report and correct the cause of the Hydrocarbon Flaring Incidents in accordance with the procedures in Koch's Flare Policy.

100. TAIL GAS INCIDENTS. For Tail Gas Incidents, Koch shall follow the same investigative, reporting, corrective action and assessment of stipulated penalty procedures as outlined in Paragraph 101 for Acid Gas Flaring. Those procedures shall be applied to TGTU shutdowns, bypasses of a TGTU, unscheduled shutdowns of a SRP or other miscellaneous unscheduled SRP events which result in a Tail Gas Incident as defined in Paragraph 95 (q), with the exceptions that the provisions of Paragraph 101(c)(ii)(A) would not apply to a Tail Gas Incident and Tail Gas Incidents would not be counted in the tally of Acid Gas Flaring Incidents under Paragraph 101(c)(ii)(B).

101. REQUIREMENTS RELATED TO ACID GAS FLARING.

(a) INVESTIGATION AND REPORTING: No later than thirty (30) days following the end of an AG Flaring Incident or an event identified in Paragraph 100, Koch shall submit a report to the applicable EPA Regional Office and applicable State Agency that sets forth the following:

(i). The date and time that the AG Flaring Incident started and ended. To the extent that the AG Flaring Incident involved multiple releases either within a twenty-four (24) hour period or within subsequent, contiguous, non-overlapping twenty-four (24) hour periods, Koch shall set forth the starting and ending dates and times of each release;

(ii). An estimate of the quantity of sulfur dioxide that was emitted and the calculations that were used to determine that quantity;

(iii). The steps, if any, that Koch took to limit the duration and/or quantity of sulfur dioxide emissions associated with the AG Flaring Incident;

(iv). A detailed analysis that sets forth the Root Cause and all contributing causes of that AG Flaring Incident, to the extent determinable;

(v). An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of a AG Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis shall discuss the alternatives, if any, that are available, the probable effectiveness and cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operational, and maintenance changes shall be evaluated. If Koch concludes that corrective action(s) is (are) required under Paragraph 101(b), the report shall include a description of the action(s) and, if not already completed, a schedule for its (their) implementation, including proposed commencement and completion dates. If Koch concludes that corrective action is not required under Paragraph 101(b), the report shall explain the basis for that conclusion;

(vi). A statement that:

(A) specifically identifies each of the grounds for stipulated penalties in Paragraphs 101(c) of this Decree and describes whether or not the AG Flaring Incident falls under any of those grounds;

(B) describes which Paragraph 101(c)(iii)(A) or (B) applies, and why, if a AG Flaring Incident falls under Paragraph 101(c)(iii) of this Decree; and

(C) states whether or not Koch asserts a defense to the AG Flaring Incident, and if so, a description of the defense if an AG Flaring Incident falls under either Paragraph 101(c)(ii) or Paragraph 101(c)(iii)(B);

(vii). To the extent that investigations of the causes and/or possible corrective actions still are underway on the due date of the report, a statement of the anticipated date by which a follow-up report fully conforming to the requirements of Paragraphs 101(a)(iv) and (v) will be submitted; provided, however, that if Koch has not submitted a report or a series of reports containing the information required to be submitted under this Paragraph within 45 days (or such additional time as EPA may allow) after the due date for the initial report for the AG Flaring Incident, the stipulated penalty provisions of Paragraph 103(b) shall apply, but Koch shall retain the right to dispute, under Part XVI (Dispute Resolution) of this Consent Decree, any demand for stipulated penalties that was issued as a result of Koch's failure to submit the report required under this Paragraph within the time frame set forth. Nothing in this Paragraph shall be deemed to excuse Koch from its investigation, reporting, and corrective action obligations under this Part for any AG Flaring Incident which occurs after an AG Flaring Incident for which Koch has requested an extension of time under this Paragraph.

(viii). To the extent that completion of the implementation of corrective action(s), if any, is not finalized at the time of the submission of the report required under this Paragraph, then, by no later than 30 days after completion of the implementation of corrective action(s), Koch shall submit a report identifying the corrective action(s) taken and the dates of commencement and completion of implementation.

(b.) CORRECTIVE ACTION: In response to any AG Flaring Incident, Koch, as expeditiously as practicable, shall take such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of that AG Flaring Incident.

(i). If EPA does not notify Koch in writing within sixty (60) days of receipt of the report(s) required by Paragraph 101(a) that it objects to one or more aspects of Koch's proposed corrective action(s), if any, and schedule(s) of implementation, if any, then that (those) action(s) and schedule(s) shall be deemed acceptable for purposes of Koch's compliance with Paragraph 101(b) of this Decree. EPA does not, however, by its agreement to the entry of this Consent Decree or by its failure to object to any corrective action that Koch may take in the future, warrant or aver in any manner that any of Koch's corrective actions in the future will result in compliance with the provisions of the Clean Air Act or its implementing regulations. Notwithstanding EPA's review of any plans, reports, corrective measures or procedures under this Section, Koch shall remain solely responsible for compliance with the Clean Air Act and its implementing regulations.

(ii). If EPA does object, in whole or in part, to Koch's proposed corrective action(s) and/or its schedule(s) of implementation, or, where applicable, to the absence of such proposal(s) and/or schedule(s), it shall notify Koch of that fact within sixty (60) days following receipt of the report(s) required by Paragraph 101(a) above. If Koch and EPA cannot agree within thirty (30) days on the appropriate corrective action(s), if any, to be taken in response to a particular AG Flaring Incident, either Party may invoke the Dispute Resolution provisions of Part XVI of this Decree.

Nothing in this Paragraph shall be construed as a waiver of EPA's rights under the Act and its regulations for future violations of the Act or its regulations. Nothing in this Paragraph shall be construed to limit Koch's right to take such corrective actions as it deems necessary and appropriate

immediately following an AG Flaring Incident or in the period during preparation and review of any reports required under this Part.

(c). AG FLARING INCIDENTS AND STIPULATED PENALTIES:

(i) The stipulated penalty provisions of Paragraph 103(a) shall apply to any AG Flaring Incident for which the Root Cause was one or more of the following acts, omissions, or events:

(A). Error resulting from careless operation by the personnel charged with the responsibility for the SRPs, TGTUs, or Upstream Process Units;

(B). A failure of equipment that is due to a failure by Koch to operate and maintain that equipment in a manner consistent with good engineering practice.

Except for a Force Majeure event, Koch shall have no defenses to demand for stipulated penalties for a AG Flaring Incident falling under this Paragraph.

(ii) The stipulated penalty provisions of Paragraph 103(a) shall apply to any AG Flaring Incident that either:

(A). Results in emissions of sulfur dioxide at a rate of greater than twenty (20) pounds per hour continuously for three (3) consecutive hours or more; or

(B). Causes the total number of AG Flaring Incidents per refinery in a rolling twelve (12) month period to exceed five (5).

In the event that an AG Flaring Incident falls under both Paragraph 101(c)(i) and (ii), then Paragraph 101(c)(i) shall apply.

(iii) With respect to any AG Flaring Incident other than those identified in Paragraphs 101(c)(i) and 101(c)(ii), the following provisions apply:

(A). First Time: If the Root Cause of the AG Flaring Incident was not a recurrence of the same Root Cause that resulted in a previous AG Flaring Incident that occurred since the effective date of this Decree for the Corpus Christi Refinery East and West, and since May 18, 1998 for Pine Bend Refinery, then:

(1). If the Root Cause of the AG Flaring Incident was sudden, infrequent, and not reasonably preventable through the exercise of good engineering practice, then that cause shall be designated as an agreed-upon malfunction for purposes of reviewing subsequent AG Flaring Incidents;

(2). If the Root Cause of the AG Flaring Incident was not sudden and infrequent, and was reasonably preventable through the exercise of good engineering practice, then Koch shall implement corrective action(s) pursuant to Paragraph 101(b).

(B) Recurrence: If the Root Cause is a recurrence of the same Root Cause that resulted in a previous AG Flaring Incident that occurred since the Effective Date of this Consent Decree, then Koch shall be liable for stipulated penalties under Paragraph 103(a) of this Decree unless:

(1) the AG Flaring Incident resulted from a Malfunction,

(2) the Root Cause previously was designated as an agreed-upon malfunction under Paragraph 101(c)(iii)(A)(1), or

(3) the AG Flaring Incident was a recurrence of an event that Koch had previously developed a corrective action plan for and for which it had not yet completed implementation.

(iv.) In response to a demand by EPA for stipulated penalties, the United States and Koch both agree that Koch shall be entitled to assert a Malfunction defense with respect to any AG Flaring Incident or Tail Gas Incident falling under this Paragraph. In the event that a dispute arising under this Paragraph is brought to the Court pursuant to the Dispute Resolution provisions of this Decree, nothing in this Paragraph is intended or shall be construed to deprive Koch of its view that Startup, Shutdown, and Malfunction upset defenses are available for AG Flaring Incidents and Tail Gas Incidents, nor to deprive the United States of its view that such defenses are not available.

(v.) Other than for a Malfunction or Force Majeure, if no AG Flaring Incident or Tail Gas Incident occurs at a refinery for a rolling 36 month period, then the stipulated penalty provisions of Paragraph 103(a) no longer apply at that refinery. EPA may elect to reinstate the stipulated penalty provision if Koch has a flaring event which would otherwise be subject to stipulated penalties. EPA's decision shall not be subject to dispute resolution. Once reinstated, the stipulated penalty provision shall continue for the remaining life of this Consent Decree.

102. MISCELLANEOUS:

(a) Calculation of the Quantity of Sulfur Dioxide

Emissions resulting from AG Flaring. For purposes of this Consent Decree, the quantity of sulfur dioxide

emissions resulting from AG Flaring shall be calculated by the following formula:

Tons of Sulfur Dioxide = $[FR][TD][ConcH_2S][8.44 \times 10^{-5}]$.

The quantity of Sulfur Dioxide emitted shall be rounded to one decimal point. (Thus, for example, for a calculation that results in a number equal to 10.050 tons, the quantity of Sulfur Dioxide emitted shall be rounded to 10.1 tons.) For purposes of determining the occurrence of, or the total quantity of Sulfur Dioxide emissions resulting from, a AG Flaring Incident that is comprised of intermittent AG Flaring, the quantity of Sulfur Dioxide emitted shall be equal to the sum of the quantities of sulfur dioxide flared during each such period of intermittent AG Flaring.

(b) Calculation of the Rate of Sulfur Dioxide Emissions during AG Flaring. For purposes of Paragraph

101(c)(ii)(A) of this Consent Decree, the rate of sulfur dioxide emissions resulting from Flaring shall be expressed in terms of pounds per hour, and shall be calculated by the following formula: $ER =$

$[FR][ConcH_2S][0.169]$. The emission rate shall be rounded

to one decimal point. (Thus, for example, for a calculation that results in an emission rate of 19.95 pounds of sulfur dioxide per hour, the emission rate shall be rounded to 20.0 pounds of sulfur dioxide per hour; for a calculation that results in an emission rate of 20.05 pounds of sulfur dioxide per hour, the emission rate shall be rounded to 20.1.)

(c) Meaning of Variables and Derivation of Multipliers

used in the Equations in Paragraphs 102(a) and 102(b):

ER = Emission Rate in pounds of Sulfur Dioxide per hour

FR = Average Flow Rate to Flaring Device(s) during Flaring, in standard cubic feet per hour

TD = Total Duration of Flaring in hours

ConcH₂S = Average Concentration of Hydrogen Sulfide in gas during Flaring (or immediately prior to Flaring if all gas is being flared) expressed as a volume fraction (scf H₂S/scf gas)

$8.44 \times 10^{-5} = [\text{lb mole H}_2\text{S}/379 \text{ scf H}_2\text{S}][64 \text{ lbs SO}_2/\text{lb mole H}_2\text{S}][\text{Ton}/2000 \text{ lbs}]$

$0.169 = [\text{lb mole H}_2\text{S}/379 \text{ scf H}_2\text{S}][1.0 \text{ lb mole SO}_2/1 \text{ lb mole H}_2\text{S}][64 \text{ lb SO}_2/1.0 \text{ lb mole SO}_2]$

The flow of gas to the AG Flaring Device(s) - "FR" - shall be as measured by the relevant flow meter or

determined by calculation. Hydrogen sulfide concentration - "ConcH₂S" - shall be determined from an SRP feed gas analyzer or by calculation. In the event that either of these data points is unavailable or inaccurate, the missing data point(s) shall be estimated according to best engineering judgment. The report required under Paragraph 101(a) shall include the data used in the calculation and an explanation of the basis for any estimates of missing data points.

(d) Calculation of the Quantity of Sulfur Dioxide Emissions resulting from a Tail Gas Incident. For the purposes of this Consent Decree, the quantity of sulfur dioxide emissions resulting from a Tail Gas Incident shall be calculated by the one of the following methods, based on the point of release:

(i) If the Tail Gas Incident is an event of flaring, the sulfur dioxide emissions are calculated as follows:

$$ER_{TGFL} = [FR_{TGFL}] [ConcH_2S] [0.169] [TD_{TGFL}]$$

Where:

ER_{TGFL} = Emission Rate in pounds of Sulfur Dioxide for Tail Gas Incident using flare

FR_{TGFL} = Average Tail Gas Flow Rate to Flaring Device(s) during Flaring, in standard cubic feet per hour

TD_{TGFL} = Total Duration for flaring of Tail Gas Incident in hours

ConcH₂S = Average Concentration of Hydrogen Sulfide in tail gas during Flaring (or immediately prior to Flaring if all gas is being flared) expressed as a volume fraction (scf H₂S/scf gas)

$$0.169 = \frac{[1 \text{ lb mole H}_2\text{S}/379 \text{ scf H}_2\text{S}][1.0 \text{ lb mole SO}_2/1 \text{ lb mole H}_2\text{S}]}{[64 \text{ lb SO}_2/1.0 \text{ lb mole SO}_2]}$$

The flow of tail gas to the Flaring Device(s) -

"FR_{TGFL}" - may be measured or estimated using engineering calculations or judgement. Hydrogen sulfide concentration - "ConcH₂S" - shall be determined or estimated from the TGTU or Claus process information.

(ii) If the Tail Gas Incident is released from a monitored SRP incinerator, then the following formula applies:

$$\mathbf{ER_{TGI}} = \frac{[FR_{Inc.}][Conc. SO_2 - 250][0.169 \times 10^{-6}]}{[TD_{TGI}]}$$

Where:

ER_{TGI} = Emissions from Tail Gas at the SRP incinerator, SO₂ lbs. over a 24 hour period

FR_{Inc.} = Incinerator Exhaust Gas Flow Rate (standard cubic feet per hour) (actual stack monitor data or engineering estimate based on the acid gas feed rate to the SRP)

Conc. SO₂ = Actual SO₂ concentration (CEM data) in the incinerator exhaust gas, ppmvd at 0% O₂ and average over 24 hour.

$0.169 \times 10^{-6} = [\text{lb mole of SO}_2 / 379 \text{ SO}_2] [64 \text{ lbs SO}_2 / \text{lb mole SO}_2] [1 \times 10^{-6}]$

TD_{TGI} = Total duration (hours) when the Incinerator CEM was exceeding 250 ppmvd at 0% O₂ on a rolling twelve hour average, in a 24 hour period.

In the event the Conc. SO₂ data point is inaccurate or not available or a flow meter for FR_{Inc.} does not exist or is inoperable, then estimates will be used based on best engineering judgement.

(e) Any disputes under the provisions of this Part shall be resolved in accordance with the Part XVI (Dispute Resolution) of this Decree.

103. STIPULATED PENALTIES UNDER THIS PART: Koch shall be liable for the following stipulated penalties for violations of the requirements of this Part. For each violation that is assessed on a "per period" basis, the

amounts identified below apply on the first day of violation and are calculated for each incremental period of violation (or portion thereof):

(a) AG Flaring Incidents for which Koch is liable under Paragraphs 101(c):

Tons Emitted in Flaring Incident	Length of Time from Commencement of Flaring within the Flaring Incident to Termination of Flaring within the Flaring Incident is 3 hours or less	Length of Time from Commencement of Flaring within the Flaring Incident to Termination of Flaring within the Flaring Incident is greater than 3 hours but less than or equal to 24 hours	Length of Time of Flaring within the Flaring Incident is greater than 24 hours
5 Tons or less	\$500 per Ton	\$750 per Ton	\$1,000 per Ton
Greater than 5 Tons, but less than or equal to 15 Tons	\$1,200 per Ton	\$1,800 per Ton	\$2,300 per Ton, up to, but not exceeding, \$27,500 in any one calendar day
Greater than 15 Tons	\$1,800 per Ton, up to, but not exceeding, \$27,500 in any one calendar day	\$2,300 per Ton, up to, but not exceeding, \$27,500 in any one calendar day	\$27,500 per calendar day for each calendar day over which the Flaring Incident lasts

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(i) For purposes of calculating stipulated penalties pursuant to this SubParagraph, only one cell within the matrix shall apply. Thus, for example, for an AG Flaring Incident in which the AG Flaring starts at 1:00 p.m. and ends at 3:00 p.m., and for which 14.5 tons of sulfur dioxide are emitted, the penalty would be \$17,400 ($14.5 \times \$1,200$); the penalty would not be \$13,900 [$(5 \times \$500) + (9.5 \times \$1200)$].

(ii) For purposes of determining which column in the table set forth in this SubParagraph applies under circumstances in which AG Flaring occurs intermittently during an AG Flaring Incident, the AG Flaring shall be deemed to commence at the time that the AG Flaring that triggers the initiation of a AG Flaring Incident commences, and shall be deemed to terminate at the time of the termination of the last episode of AG Flaring within the AG Flaring Incident. Thus, for example, for AG Flaring within an AG Flaring Incident that (A) starts at 1:00 p.m. on Day 1 and ends at 1:30 p.m. on Day 1; (B) recommences at 4:00 p.m. on Day 1 and ends at 4:30 p.m. on Day 1; (C) recommences at 1:00 a.m. on Day 2 and ends at 1:30 a.m. on Day 2; and (D) no further AG Flaring occurs within the AG Flaring Incident, the AG Flaring within the AG Flaring Incident shall be deemed to last 12.5 hours -- not 1.5 hours -- and the column for AG Flaring of "greater than 3 hours but less than or equal to 24 hours" shall apply.

(b) Failure to timely submit any report required by this Part, or for submitting any report that does not conform to the requirements of this Part:

\$5,000 per week, per report.

(c) For those corrective action(s) which Koch is required to undertake following Dispute Resolution, then, from the 91st day after EPA's receipt of Koch's report under Paragraph 101(b) of this Decree until the date that

either (i) a final agreement is reached between U.S. EPA and Koch regarding the corrective action or (ii) a court order regarding the corrective action is entered:

\$5,000 per month

(d) Failure to complete any corrective action under Paragraph 101(b) of this Decree in accordance with the schedule for such corrective action agreed to by Koch or imposed on Koch pursuant to the Dispute Resolution provisions of this Decree (with any such extensions thereto as to which EPA and Koch may agree in writing):

\$5,000 per week

104. Certification. All notices, reports or any other submissions required of Koch by this Part shall contain the following certification:

"I certify under penalty of law that I have personally examined and am familiar with the information submitted herein and that I have made a diligent inquiry of those individuals immediately responsible for obtaining the information and that to the best of my knowledge and belief, the information submitted herewith is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment."

105. The reporting requirements set forth in this Part do not relieve Koch of its obligation to any State, local authority, or EPA to submit any other reports or information required by the CAA, or by any other state, federal or local requirements.

VIII. PERMITTING

106. Construction. Koch agrees to apply for and make all reasonable efforts to obtain in a timely manner all appropriate federally enforceable permits (or construction permit waivers) for the construction of the pollution control technology required to meet the above pollution reductions.

107. Operation. As soon as practicable, but in no event later than 60 days following a final determination of concentration limits, Koch shall apply for and make all reasonable efforts to incorporate the concentration limits required by this Consent Decree into NSR and other applicable permits for these facilities. Koch shall apply to incorporate NSPS applicability, where appropriate, into the relevant permits as set forth in Paragraph 106 above.

108. The Pine Bend Project. The parties agree that Koch initiated the planning of a project involving modifications to the #2 Crude Unit at the Pine Bend refinery prior to the signing of the Agreement in Principle dated June 30, 2000. This project is reflected in an air permit application submitted to the MPCA dated September 11, 2000. Among other things, Koch has proposed to install, as part of this

project, a new heater (11H-6). While not subject to the terms of this Consent Decree, Koch has agreed to install "next generation" ultra low NO_x burners, as defined in this Consent Decree, in 11H-6 and to eliminate fuel oil firing at all heaters involved in this project. As a result, the project will result in reduced NO_x and SO₂ emissions. The parties agree that this project should be carried out in furtherance of the objectives of this Consent Decree. The parties also recognize the existence of the Findings and Order by Stipulation (Administrative Order), dated February 25, 1994, between Koch Refining Company (now Koch Petroleum Group) and MPCA. The Administrative Order was made part of the State Implementation Plan (SIP) for sulfur dioxide attainment in Minnesota. Koch is involved in a process to revise the Administrative Order and SIP to allow Koch to ~~implement~~ implement the projects set forth in this Consent Decree. The parties believe that these projects will further the goals of the Administrative Order and SIP, to reduce sulfur dioxide emissions to the ambient air. Therefore, the parties agree that so long as Koch conforms to the terms and conditions of the Consent Decree as it pertains to pollution reduction measures related to SO₂ emissions, MPCA will take no action

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against Koch for the failure to obtain a modification of the Administrative Order prior to construction of the new heaters. The parties agree to work expeditiously towards the modification of the Administrative Order and SIP to address construction and operation of the new heater, as well as to facilitate issuance of the Title V permit for the Pine Bend refinery and approvals for other projects required by this Consent Decree. If Koch submits timely and appropriate documentation to support the SIP revision, then no violation of the construction schedule in this Consent Decree will result if the SIP revision is otherwise delayed.

IX. ENVIRONMENTALLY BENEFICIAL PROJECTS

109. Koch and the United States agree that measures to reduce NO_x and SO₂ emissions from the FCCUs and heaters and boilers at the Pine Bend and Corpus Christi refineries, to the extent that they are not otherwise required by law, are pollution reduction projects and shall be considered for penalty mitigation pursuant to this Consent Decree.

110. Koch shall perform the following pollution reduction projects:

(a.) Limitation of supplemental fuel oil burning at the Pine Bend refinery to 100,000 barrels per year at all process heaters and steam boilers (except where Koch can demonstrate that natural gas curtailment is an issue and fuel oil use is required as a back-up). This project will prevent approximately 400 tons of SO₂ emissions per year;

(b.) Installation of flare gas recovery system at the Corpus Christi East refinery;

(c.) Replacement, shutdown, or control of heaters and boilers to reduce NO_x emissions at the three refineries;

(d.) Reduction of NO_x emissions from the FCCUs at the three refineries; and

(e.) Continue the restriction on burning of any fuel oil in any of the heaters and boilers at the Corpus Christi East and West refineries.

111. Koch agrees that in any public statements regarding the funding of the projects identified in this Part, Koch must clearly indicate that these projects are being undertaken pursuant to this Consent Decree. Except as provided in Part IV, Section E (Emission Credit Generation and Classification), Koch shall not use or rely on the emission reductions generated as a result of its performance of these projects.

X. INCORPORATION OF RCRA CONSENT AGREEMENT AND FINAL ORDER

112. On August 31, 2000, EPA and Koch entered into a Consent Agreement and Final Order ("CAFO") resolving alleged

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RCRA violations at Koch's Pine Bend, Minnesota refinery, EPA docket number RCRA-5-2000-010. The terms of the CAFO are hereby incorporated by reference and are fully enforceable by and through the relevant terms of this Consent Decree. Koch's payment of \$3.5 million in civil penalties as referenced in the CAFO shall be paid pursuant to Paragraph 117 of this Consent Decree. Stipulated penalties due under the CAFO shall be paid as provided in the CAFO, and if not timely paid may be enforced under the CAFO or this Consent Decree. A copy of the CAFO is attached to this Consent Decree as Attachment 3.

XI. GENERAL RECORDKEEPING, RECORD RETENTION, AND REPORTING

113. Defendant shall retain all records required to be maintained in accordance with this Consent Decree for a period of five (5) years unless other regulations require the records to be maintained longer.

114. Beginning with the first full calendar quarter after entry of this Consent Decree, the Defendant shall submit a calendar quarterly progress report ("calendar quarterly report") to EPA within 30 days after the end of

each of the calendar quarters during the life of this Consent Decree. This report shall contain the following:

- (a.) progress report on the implementation of the requirements of Parts IV-VIII (Compliance Programs) above;
- (b.) a summary of all Hydrocarbon Flaring Incidents;
- (c.) a summary of the emissions data as required by Parts IV-VIII, of this Consent Decree for the calendar quarter;
- (d.) a description of any problems anticipated with respect to meeting the Compliance Programs of Parts IV-VIII of this Consent Decree; and
- (e.) a description of all environmentally beneficial projects and implementation activity in accordance with Part IX this Consent Decree.

115. The calendar quarterly report shall be certified by a refinery manager or corporate officer responsible for environmental management and compliance at the refineries covered by the report, as follows:

"I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete."

XII. CIVIL PENALTY

116. Within thirty (30) calendar days of entry of this Consent Decree, the Defendant shall pay to the United States a civil penalty in the amount of \$4.5 million dollars (\$4,500,000). Of the total, \$3.5 million shall be paid in settlement of the United States' RCRA claims at the Pine Bend refinery and \$75,000 shall be paid to the EPA Hazardous Substances Superfund in settlement of the United States' CERCLA claims at Pine Bend. No amount of the civil penalties assessed relate to compliance issues at the Corpus Christi East refinery. Moreover, none of the civil penalties are attributable to alleged violations of the Benzene Waste NESHAP. Penalties for the Benzene Waste NESHAP violations are being addressed exclusively by a pending criminal action entitled U.S. v. Koch Industries, et al., (S.D. TX) Docket # ~~11-111~~ C-00-325.

117. The monies shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-07110, and the civil action case name and case number of the District of Minnesota. The costs of such EFT shall be Koch's

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responsibility. Payment shall be made in accordance with instructions provided to Koch by the Financial Litigation Unit of the U.S. Attorney's Office in the District of Minnesota. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Koch shall provide notice of payment, referencing the USAO File Number and DOJ Case Number 90-5-2-1-07110, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 148 (Notice).

118. Upon entry of this Decree, this Decree shall constitute an enforceable judgment for purposes of post-judgment collection in accordance with Rule 69 of the Federal Rules of Civil Procedure, the Federal Debt Collection Procedure Act, 28 U.S.C. § 3001-3308, and other applicable federal authority. The United States shall be deemed a judgment creditor for purposes of collection of any unpaid amounts of the civil and stipulated penalties and interest.

119. No amount of the civil penalty to be paid by Koch shall be used to reduce its federal or state tax obligations.

XIII. STIPULATED PENALTIES

120. The Defendant shall pay stipulated penalties to the United States or the MPCA, where appropriate, for each

failure by the Defendant to comply with the terms of this Consent Decree; provided, however, that the United States or the MPCA may elect to bring an action for contempt in lieu of seeking stipulated penalties for violations of this Consent Decree. For each violation, the amounts identified below shall apply on the first day of violation, shall be calculated for each incremental period of violation (or portion thereof), and shall be doubled beginning on the fourth consecutive, continuing period of violation, except such doubling shall not apply to Paragraphs 120(f) and 120(g)(i). In the alternative, at the option of the United States or the MPCA, stipulated penalties shall equal 1.2 times the economic benefit of Koch's delayed compliance, if this amount is higher than the amount calculated under this Paragraph.

(a.) Requirements for NO_x emission reductions from heaters and boilers (Part IV, Section A):

(i) Failure to install all the required burners by the December 31, 2006 deadline:
\$75,000 per quarter per unit

(ii) Failure to test for emissions or failure to establish operating parameters:
\$2000 per month per unit

(iii) Failure to meet the emission limits established pursuant to Part IV, Section A: \$800 per day for each heater or boiler with capacity of 150 mmBTU/hr (HHV) or greater;

\$400 per day for each heater or boiler with capacity of less than 150 mmBTU/hr (HHV);

(iv) Failure to install CEMS: \$20,000 per month per unit

(v) Failure to submit the written proposals, feasibility determinations or annual reports to EPA pursuant to this Part: \$1000 per proposal/determination/report per month

(b.) Requirements for NO_x emission reductions from FCCUs

(Part IV, Section B):

(i) Failure to conduct NO_x additive demonstrations: \$30,000 per month per refinery

(ii) Failure to install SNCR on any one FCCU, or an alternative technology: \$100,000 per quarter per refinery

(iii) Failure to meet emission limits established pursuant to Part IV, Section B: \$1500 per day per unit

(iv) Failure to prepare a final report as required by Part IV, Section B: \$1,000 per week per report

(c.) Requirements for SO₂ emission reductions from FCCUs

(Part IV, Section C):

(i) Failure to meet interim emission limits for the FCCU exhaust gas at Pine Bend:

\$1500 per day

(ii) Failure to timely conduct optimization studies of the wet gas scrubbers at Corpus Christi West and East:

\$5000 per month per unit

(iii) Failure to meet final emission limits for the FCCU exhaust gas at each refinery:

\$3000 per day per unit

(d.) Requirements for Benzene Waste NESHAP program

enhancements (Part V):

(i) Failure to timely conduct audit under Paragraph 64:

\$5,000 per month per audit

(ii) Failure to timely sample under Paragraph 66:
\$5,000 per week or \$30,000 per quarter, per stream
(whichever amount is greater, but not to exceed
\$150,000 per refinery per quarter)

(iii) Failure to timely install carbon canister under Paragraph 68(a):

\$5,000 per week per canister

(iv) Failure to timely replace carbon canister under Paragraph 68(d):

\$1,000 per day per canister

(v) Failure to perform monthly monitoring under Paragraph 71(a):

\$500 per month per drain

(vi) Failure to develop and timely implement training program under Paragraph 71(c):

\$10,000 per quarter per refinery

(vii) Failure to mark segregated stormwater drains under Paragraph 71(f):

\$1,000 per week per drain

(viii) Failure to complete timely evaluations under Paragraph 72:

\$500 per week per evaluation

(ix) Failure to timely submit reports under this Part:

\$1,000 per week per report

(x) If it is discovered by an EPA or state investigator or inspector, or their agent, that Koch failed to include all benzene waste streams in its TAB, for each waste stream that is:

less than 0.03 Mg/yr - \$250

between 0.03 and 0.1 Mg/yr - \$1000

between 0.1 and 0.5 Mg/yr - \$5000

greater than 0.5 Mg/yr - \$10,000

(e) Requirements for Leak Detection and Repair program enhancements (Part VI):

(i). Failure to have a written LDAR program under Paragraph 75:

\$3000 per week

(ii) Failure to timely develop training program under Paragraph 77:

\$10,000 per month

(iii) Failure to timely conduct internal or external audit under Paragraph 78:

\$5,000 per month per audit

(iv) Failure to timely implement internal leak definition under Paragraph 79:

\$10,000 per month per process unit

(v) Failure to develop and timely implement first attempt at repair program under Paragraph 80:
\$10,000 per month

(vi) Failure to implement and begin more frequent monitoring program under Paragraph 81:
\$10,000 per month per process unit

(vii) Failure to timely monitor under Paragraph 81 and 82:
\$5,000 per week per process unit

(viii) Failure to have dataloggers and electronic storage under Paragraph 83:
\$5,000 per month per refinery

(ix) Failure to establish new equipment standards under Paragraph 84:
\$1,000 per month

(x) Failure to implement subcontractor requirements (if required) under Paragraph 85:
\$5,000 per month per refinery

(xi) Failure to timely establish LDAR accountability under Paragraph 86:
\$5,000 per month per refinery

(xii) Failure to timely implement maintenance tracking program under Paragraph 88:
\$5,000 per month per refinery

(xiii) Failure to conduct calibration drift assessment or to remonitor components (if and as required) under Paragraph 90:
\$100 per day per refinery

(xiv) Failure to attempt "heroic" repairs under Paragraph 91:
\$5,000 per component

(xv) Failure to timely submit reports required under this Part:

\$1,000 per week per report

(xvi) If it is discovered by an EPA or state investigator or inspector, or their agent, that Koch failed to include all required components in its LDAR program:
\$250 per component

(f) Requirements for NSPS Applicability to SRPs (Part VII):

(i) For those events not otherwise covered by Paragraph 100 (i.e., Tail Gas Incidents), each rolling 12-hour average of sulfur dioxide emissions from any SRP in excess of the limitation at 40 C.F.R. § 60.104(a)(2)(i) that is not attributable to Startup, Shutdown, or Malfunction of the SRP, or that is not attributable to Malfunction of the associated TGTU:

Number of rolling 12-hr average exceedances within calendar day	Penalty per rolling 12-hr average exceedance
1-12	\$ 350
Over 12	\$ 750

(ii) Operation of the SRP during Scheduled Maintenance of its associated TGTU (except that this Paragraph shall not apply during the period in which Koch is engaged in the Shutdown of an SRP for, or Startup of an SRP following, Scheduled Maintenance of the SRP):
\$25,000 per SRP per day

(g) Requirements for SRU Optimization and Flaring (Part VII):

(i) Stipulated penalties as identified and enumerated in Paragraph 103

(ii) Failure to operate and maintain properly a flare gas recovery system pursuant to Koch's Flare Policy (Attachment 2) (this requirement does not apply to Corpus Christi East until January 7, 2004):
\$1,000 per day per refinery

(iii) Failure to timely install a flare gas recovery system at the Corpus Christi East refinery:
\$100,000 per quarter

(h) Requirements for Permitting (Part VIII):

Failure to timely submit a complete permit application under Paragraph 106 or 107 &:
\$1,000 per week per unit

(i) Requirements for Pollution Reduction Projects (Part IX);

Oil burning in violation of Paragraph 110:
\$15 per barrel

(j) Requirements for Reporting and Recordkeeping (Part XI):

Failure to timely submit a report required under Part XI:
\$1,000 per week per report

(k) Requirement to pay a Civil Penalty and to Escrow

Stipulated Penalties:

(i) Failure to timely pay the civil penalty specified in Part XII of this Consent Decree:

\$20,000 per week, plus interest on the amount overdue at the rate specified in 31 U.S.C. § 3717.

(ii) Failure to escrow stipulated penalties as required by Paragraph 122:
\$10,000 per week

121. Koch shall pay such stipulated penalties only upon written demand by the United States or the MPCA no later than thirty (30) days after Defendant receives such demand. Such demand will identify to which government agencies payment must be made. Stipulated penalties shall be paid to either the United States or the MPCA, unless the total amount of the stipulated penalty is apportioned between the United States and the MPCA. Such payment shall be made to the United States in the manner set forth in Part XII (Civil Penalty) of this Consent Decree, and to MPCA for deposit in the State Environmental Response, Compensation and Compliance Fund, and the environmental fund in the state treasury referred to in Minnesota Statutes Chapter 115.072.

122. Should Koch dispute its obligation to pay part or all of a stipulated penalty, it may avoid the imposition of the stipulated penalty for failure to pay a penalty due to the United States or the MPCA, by placing the disputed amount

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demand by the United States or the MPCA, not to exceed \$50,500 for any given event or related series of events at any one refinery, in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of Part XVI within the time provided in this Paragraph for payment of stipulated penalties. If the dispute is thereafter resolved in Defendant's favor, the escrowed amount plus accrued interest shall be returned to the Defendant, otherwise the United States or MPCA shall be entitled to the escrowed amount that was determined to be due by the Court plus the interest that has accrued on such amount, with the balance, if any, returned to the Defendant.

123. The United States and the MPCA reserve the right to pursue any other remedies to which they are entitled, including, but not limited to, additional injunctive relief for Defendant's violations of this Consent Decree. Nothing in this Consent Decree shall prevent the United States or the MPCA from pursuing a contempt action against Koch and requesting that the Court order specific performance of the terms of the Decree. Nothing in this Consent Decree authorizes MPCA to take action or make any determinations

under this Consent Decree regarding Koch refineries outside the state of Minnesota.

124. Election of Remedy. The United States and the MPCA will not seek both stipulated penalties and civil penalties for the same actions or occurrences as those constituting a violation of the Consent Decree.

XIV. RIGHT OF ENTRY

125. Any authorized representative of the EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Koch's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment, and inspecting and copying all records maintained by Defendant required by this Consent Decree.

Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections under Section 114 of the Act, 42 U.S.C. § 7414, or any other statutory and regulatory provision.

XV. FORCE MAJEURE

126. If any event occurs which causes or may cause a delay or impediment to performance in complying with any

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provision of this Consent Decree, Koch shall notify the United States and the MPCA, if the issue relates to the Pine Bend Refinery, in writing as soon as practicable, but in any event within twenty (20) business days of when Koch first knew of the event or should have known of the event by the exercise of due diligence. In this notice Koch shall specifically reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, and the measures taken or to be taken by Koch to prevent or minimize the delay and the schedule by which those measures will be implemented. Koch shall adopt all reasonable measures to avoid or minimize such delays.

127. Failure by Koch to comply with the notice requirements of Paragraph 126 as specified above shall render this Part XV voidable by the United States or the MPCA, if applicable to the Pine Bend refinery, as to the specific event for which Koch has failed to comply with such notice requirement, and, if voided, it shall be of no effect as to the particular event involved.

128. The United States and MPCA shall notify Koch in writing regarding Koch's claim of a delay or impediment to

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performance within twenty (20) business days of receipt of the Force Majeure notice provided under Paragraph 126. If the United States and MPCA, if applicable to the Pine Bend refinery, agree that the delay or impediment to performance has been or will be caused by circumstances beyond the control of Koch, including any entity controlled by Koch, and that Koch could not have prevented the delay by the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay by a period equivalent to the delay actually caused by such circumstances, or such other period as may be appropriate in light of the circumstances. Such stipulation may be filed as a modification to this Consent Decree by agreement of the parties pursuant to the modification procedures established in this Consent Decree. Koch shall not be liable for stipulated penalties for the period of any such delay.

129. If the United States or the MPCA, if applicable to the Pine Bend refinery, do not accept Koch's claim of a delay or impediment to performance, Koch must submit the matter to this Court for resolution to avoid payment of stipulated penalties, by filing a petition for determination with this

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Court. In the event that the United States and MPCA are unable to reach agreement on acceptance of Koch's claim of a delay or impediment to performance under this Part, the final decision of the United States shall be binding. Once Koch has submitted this matter to this Court, the United States and MPCA, if applicable to the Pine Bend refinery, shall have twenty (20) business days to file its response to said petition. If Koch submits the matter to this Court for resolution and the Court determines that the delay or impediment to performance has been or will be caused by circumstances beyond the control of Koch, including any entity controlled by Koch, and that Koch could not have prevented the delay by the exercise of due diligence, Koch shall be excused as to that event(s) and delay (including stipulated penalties), for all requirements affected by the delay for a period of time equivalent to the delay caused by such circumstances or such other period as may be determined by the Court.

130. Koch shall bear the burden of proving that any delay of any requirement(s) of this Consent Decree was caused by or will be caused by circumstances beyond its control, including any entity controlled by it, and that Koch could not have

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prevented the delay by the exercise of due diligence. Koch shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but does not necessarily, result in an extension of a subsequent compliance date or dates.

131. Unanticipated or increased costs or expenses associated with the performance of Koch's obligations under this Consent Decree shall not constitute circumstances beyond the control of Koch, or serve as a basis for an extension of time under this Part. However, failure of a permitting authority to issue a necessary permit in a timely fashion is an event of Force Majeure where the failure of the permitting authority to act is beyond the control of Koch and Koch has taken all steps available to it to obtain the necessary permit including but not limited to:

- (a.) submitting a complete permit application;
- (b.) responding to requests for additional information by the permitting authority in a timely fashion;
- (c.) accepting lawful permit terms and conditions; and
- (d.) prosecuting appeals of any unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

132. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of Koch delivering a notice of Force Majeure or the parties' inability to reach agreement.

133. As part of the resolution of any matter submitted to this Court under this Part XV, the parties by agreement, or this Court, by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay or impediment to performance agreed to by the United States or approved by this Court. Defendant shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XVI. DISPUTE RESOLUTION

134. The dispute resolution procedure provided by this Part XVI shall be available to resolve all disputes arising under this Consent Decree, except as otherwise provided in Part XV regarding Force Majeure, provided that the party making such application has made a good faith attempt to resolve the matter with the other party. In the event that

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the United States and MPCA make differing determinations or take differing actions that affect Koch's rights or obligations under this Consent Decree, the final decision of the United States shall be binding.

135. The dispute resolution procedure required herein shall be invoked upon the giving of written notice by one of the parties to this Consent Decree to another advising of a dispute pursuant to this Part XVI. The notice shall describe the nature of the dispute, and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice and the parties shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days from the receipt of such notice.

136. Disputes submitted to dispute resolution shall, ~~in~~ the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States or the MPCA, if applicable to the Pine Bend refinery, and the Defendant, unless the parties' representatives agree to shorten or extend this period.

137. In the event that the parties are unable to reach agreement during such informal negotiation period, the United States or the MPCA, if applicable to the Pine Bend refinery, shall provide the Defendant with a written summary of its position regarding the dispute. The position advanced by the United States or the MPCA, if applicable to the Pine Bend refinery, shall be considered binding unless, within forty-five (45) calendar days of the Defendant's receipt of the written summary of the United States' or the MPCA's position, the Defendant files with this Court a petition which describes the nature of the dispute. In the event that the position advanced by the United States differs from the position advanced by the MPCA, if applicable to the Pine Bend refinery, the position of the United States shall be considered binding unless, within forty-five (45) calendar days of the Defendant's receipt of the written summary of the United States' position, the Defendant files with this Court a petition which describes the nature of the dispute. The United States or the MPCA, if applicable to the Pine Bend refinery, shall respond to the petition within forty-five (45) calendar days of filing.

138. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Part XVI may be shortened upon motion of one of the parties to the dispute.

139. Notwithstanding any other provision of this Consent Decree, in dispute resolution, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Part XVI or the parties' inability to reach agreement.

140. As part of the resolution of any dispute submitted to dispute resolution, the parties, by agreement, or this Court, by order, may, in appropriate circumstances, extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of dispute resolution. Defendant shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XVII. EFFECT OF SETTLEMENT

141. Satisfaction of all of the requirements of this Consent Decree constitutes full settlement of and shall resolve all civil liability of the Defendant to the United

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States and the Plaintiff-Intervener for the violations alleged in the United States' and Plaintiff-Intervener's Complaints and all civil liability of the Defendant for any violations at its Pine Bend and Corpus Christi East and West refineries based on events that occurred during the relevant time period under the following statutory and regulatory provisions: the New Source Performance Standards ("NSPS"), 40 C.F.R. Part 60, Subpart J; Leak Detection and Repair ("LDAR"), 40 C.F.R. Part 60, Subparts VV and GGG, and 40 C.F.R. Part 63, Subparts F, H, and CC; National Emission Standards for Hazardous Air Pollutants ("NESHAP") for Benzene, 40 C.F.R. Part 61, Subparts FF, J and V pursuant to Section 112(d) of the Act; and the Minnesota and Texas regulations which incorporate and/or implement the above-listed federal regulations. For purposes of this Consent Decree the "relevant time period" shall mean the period beginning when the United States' claims and/or Plaintiff-Intervener's claims under the above statutes and regulations accrued through the date of entry of the Consent Decree. Koch's performance of all requirements of this Consent Decree shall resolve all civil liability under the Prevention of Significant Deterioration ("PSD") requirements at Part C of

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the Act, and the regulations promulgated thereunder at 40 C.F.R. § 52.21 (the "PSD" rules), and the Minnesota and Texas regulations which incorporate and/or implement those rules, for any increase in SO₂ and NO_x emissions resulting from Koch's construction, modification, or operation of the following process units occurring prior to entry of the Consent Decree: FCCUs, SRPs, and all process heaters and boilers at the Pine Bend, Corpus Christi East and West refineries, referred to in this Consent Decree as "netting units"; and for CO and PM emissions from the FCCUs. During the life of the Consent Decree, these units shall be on a compliance schedule and any modification to these units, as defined in 40 C.F.R. § 52.21, which is not required by this Consent Decree is beyond the scope of this release.

142. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with any applicable federal, state or local laws or regulations. Nothing in this Consent Decree shall be construed to be a ruling on, or determination of, any issue related to any federal, state or local permit.

XVIII. GENERAL PROVISIONS

143. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Defendant of its obligation to comply with all applicable federal, state and local laws and regulations. Subject to Paragraph 124 (Election of Remedy), nothing contained in this Consent Decree shall be construed to prevent, alter or limit the ability of the United States' or the MPCA's rights to seek or obtain other remedies or sanctions available under other federal, state or local statutes or regulations, by virtue of Defendant's violation of this Consent Decree or of the statutes and regulations for violations of this Consent Decree. This shall include the United States' or the MPCA's right to invoke the authority of the Court to order Koch's compliance with this Consent Decree in a subsequent contempt action.

144. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

145. Costs. Each party to this action shall bear its own costs and attorneys' fees.

146. Public Documents. All information and documents submitted by the Defendant to the United States or the MPCA pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by the Defendant in accordance with 40 C.F.R. Part 2, or any equivalent state statutes and regulations.

147. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and consideration of any comments.

148. Notice. Unless otherwise provided herein, notifications to or communications with the United States or the Defendant shall be deemed submitted on the date they are postmarked and sent either by overnight receipt mail service or by certified or registered mail, return receipt requested. When Koch is required to submit notices or communicate in writing under this Consent Decree to EPA relating to the Pine Bend Refinery, Koch shall also submit a copy of that notice or other writing to the Plaintiff-Intervener, State of

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Minnesota. Similarly Koch shall submit such copies to the State of Texas where notices or other written communications relate to the Corpus Christi East and West refineries.

Except as otherwise provided herein, when written notification or communication is required by this Consent Decree, it shall be addressed as follows:

As to the United States:

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611

United States Attorney
District of Minnesota
234 United States Courthouse
110 South Fourth Street
Minneapolis, Minnesota 55401

As to EPA:

Director
Air Enforcement Division (2242A)
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

With copies to the appropriate EPA Regional offices:

Chief
Air Enforcement and Compliance Assurance Branch
Air and Radiation Division, AE-17J
U.S. Environmental Protection Agency

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Region 5
77 West Jackson Boulevard
Chicago, Illinois 60604-3590
Attn: Compliance Tracker

Chief
Air, Toxics, and Inspection Coordination Branch (6EN-A)
Compliance Assurance and Enforcement Division
U.S. Environmental Protection Agency
Region 6
1445 Ross Avenue
Dallas, Texas 75202
As to Koch Petroleum Group, L.P.:

James L. Mahoney
Executive Vice President, Operations
Koch Petroleum Group, L.P.
P.O. Box 2256
Wichita, KS 67201

with copies to:

William A. Frerking
Associate General Counsel
Koch Industries, Inc.
P.O. Box 2256
Wichita, KS 67201

As to Plaintiff-Intervener the State of Minnesota:

Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155

As to the State of Texas:

Texas Natural Resource and Conservation Commission
Corpus Christi Regional Office
6300 Ocean Drive
Suite 1200
Corpus Christi, TX 78412-5503

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149. All EPA approvals or comments required under this Decree shall come from EPA, AED at the address listed in Paragraph 148.

150. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

151. The information required to be maintained or submitted pursuant to this Consent Decree is not subject to the Paperwork Reduction Act of 1980, 44 U.S.C. §§ 3501 et seq.

152. This Consent Decree shall be binding upon all Parties to this action, and their successors and assigns. The undersigned representative of each Party to this Consent Decree certifies that he or she is duly authorized by the Party whom he or she represents to enter into the terms and bind that Party to them.

153. Modification. This Consent Decree may be modified only by the written approval of the United States, Koch, and the MPCA, if applicable to Pine Bend, or by Order of the Court.

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154. Continuing Jurisdiction. The Court retains jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

155. This Consent Decree constitutes the entire agreement and settlement between the Parties.

XIX. TERMINATION

156. This Consent Decree shall be subject to termination upon motion by either party after the Defendant satisfies all requirements of this Consent Decree. The requirements for termination include payment of all penalties, including stipulated penalties, that may be due to the United States under this Consent Decree, installation of control technology systems as specified herein and the performance of all other Consent Decree requirements, the receipt of all permits specified herein, EPA's receipt of the first calendar quarterly progress report following the conclusion of Koch's operation for at least one year of all

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units in compliance with the emission limits established herein. At such time, if Koch believes that it is in compliance with the requirements of this Consent Decree and the permits specified herein, and has paid the civil penalty and any stipulated penalties required by this Consent Decree, then Koch shall so certify to the United States, and unless the United States objects in writing with specific reasons within 120 days of receipt of the certification, the Court shall order that this Consent Decree be terminated on Koch's motion. If the United States so objects to Koch's certification, then the matter shall be submitted to the Court for resolution under Part XVI (Dispute Resolution) of this Consent Decree. In such case, Koch shall bear the burden of proving that this Consent Decree should be terminated. Provided, however, that if Koch has incorporated all requirements set forth in Parts V and VI of this Consent Decree (Benzene Waste NESHAP and LDAR enhanced programs) in a refinery's federally enforceable operating permit, Koch may

petition EPA to terminate those Parts of the Consent Decree
as to any such refinery at any time thereafter.

So entered in accordance with the foregoing this 12th day
of

April, 2001.

A handwritten signature in black ink, appearing to read "J. Paul Magnus", written over a horizontal line.

United States District Court Judge
for the District of Minnesota

FOR PLAINTIFF, UNITED STATES OF AMERICA:

Robert M. Small
Acting United States Attorney

By:



Friedrich A.P. Siekert
Attorney I.D. No. 142013
Assistant United States Attorney
234 United States Courthouse
110 South Fourth Street
Minneapolis, Minnesota 55401

Date: 12/22/00

Lois J. Schiffer

Date 11/12/00

Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources Division
U.S. Department of Justice
10th & Pennsylvania Avenue, N.W.
Washington, DC 20530

Dianne M. Shawley

Date 10/25/00

Dianne M. Shawley
Senior Attorney
Environment and Natural Resources Division
U.S. Department of Justice
1425 New York Avenue, N.W.
Washington, DC 20005

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FOR U.S. ENVIRONMENTAL PROTECTION AGENCY:

SAK L

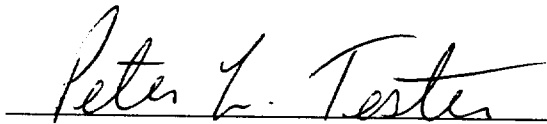
Date 12/20/00

Steven A. Herman
Assistant Administrator
Office of Enforcement and Compliance
Assurance
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

FOR PLAINTIFF-INTERVENER the STATE OF MINNESOTA:

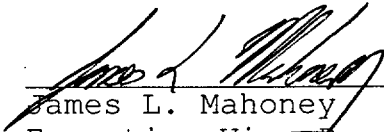
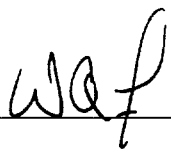
A handwritten signature in cursive script, reading "Gordon E. Wegwart", written over a horizontal line.

Gordon E. Wegwart, P.E.
Assistant Commissioner
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155

A handwritten signature in cursive script, reading "Peter L. Tester", written over a horizontal line.

Peter L. Tester
Assistant Attorney General
Minnesota Attorney General's Office
445 Minnesota Street
900 North Central Like Tower
St. Paul, Minnesota 55101

FOR KOCH PETROLEUM GROUP, L.P.

 
James L. Mahoney
Executive Vice President, Operations
P.O. Box 2256
Wichita, Kansas 67201

Date 9-29-00

ATTACHMENT 1

Sustainable Skip Period Monitoring Program

For Purposes of this Consent Decree, the following skip rules shall apply to Koch's Pine Bend and Corpus Christi West and East refineries in lieu of 40 C.F.R. 63.168(d)(2) - (4) and 40 C.F.R. 60.483-2(b)(2) - (3).

1. Koch may move to less frequent monitoring on a unit-by-unit basis using the following criteria:
 - a. At process units that have less than 2 percent leaking valves for 2 consecutive months, the owner or operator shall monitor each valve once every quarter, beginning with the next quarter.
 - b. After 2 consecutive quarterly leak detection periods with the percent of leaking valves less than or equal to 1 percent, the owner or operator may elect to monitor each valve once every 2 quarters.
 - c. After 3 consecutive semi-annual leak detection periods with the percent of valves leaking less than or equal to 0.5 percent, the owner or operator may elect to monitor each valve once every 4 quarters.
2. Koch must return to more frequent monitoring on a unit-by-unit basis using the following criteria:
 - a. If a process unit on a quarterly, semi-annual or annual monitoring schedule has a leak percentage greater than or equal to 2 percent in any single detection period, the owner or operator shall monitor each valve no less than every month, but can again elect to advance to less frequent monitoring pursuant to the schedule in 1, above.
 - b. If a process unit on a semi-annual or annual monitoring schedule has a leak percentage greater than or equal to 1 percent, but less than 2 percent in any single detection period, the owner or operator shall monitor each valve no less than quarterly, but can again elect to advance to less frequent monitoring pursuant to the schedule in 1, above.
 - c. If a process unit on an annual monitoring schedule has a leak percentage greater than or equal to 0.5

percent but less than 1 percent in any single detection period, the owner or operator shall monitor each valve no less than semi-annually, but can again elect to advance to less frequent monitoring pursuant to the schedule in 1, above.

ATTACHMENT 2
Koch Petroleum Group
Flare Policy

This document describes the process by which Koch Petroleum Group manages its flare systems at its refineries in Pine Bend, Minnesota and Corpus Christi, Texas.¹ The intent of this policy is to meet the requirements of NSPS Subpart A & J as that requirement may apply to process streams that are vented to the flare system. The primary goals of this policy are to avoid flaring through implementation of good engineering practices and to minimize the environmental impact of non-normal refinery operations through implementation of good air pollution control practices.

Koch proposes to comply with the requirements of Subpart J by not combusting process streams unless such combustion is in conformance with this policy. This policy defines startup, shutdown, malfunction and upset conditions for Koch's Refineries utilizing their flare gas recovery systems along with their procedures to (1) avoid and/or minimize flaring in reasonably foreseeable circumstances; (2) demonstrate good air pollution control practices during flaring events; and (3) seek continuous improvement by conducting root cause failure analyses on significant flaring events.

¹As you are aware, Koch has two refineries in Corpus Christi, referred to as the West and East Refineries. The West Refinery is equipped with a flare gas recovery system which is similar to, although not as large or robust as, the system at the Pine Bend Refinery. As you are also aware, the Corpus East Refinery currently does not have a flare gas recovery system, however, Koch will be installing one, pursuant to the Consent Decree. It will be subject to this policy when it is installed and operating.

Koch's three part approach is summarized as follows:

1. To follow good engineering practices that provide for a well-managed and well maintained flare system as well as the equipment that relieves to the flare system. To Koch, this means:
 - A. A flare gas recovery system designed and operated to capture most anticipated loads to the flare system.
 - B. A management system designed to keep the base load into the flare system within the system's recovery capacity.
 - C. A management system designed to minimize, and, if feasible, prevent, unexpected loads to or unexpected failure of the flare gas recovery system.
2. To follow good engineering practices and good air pollution control practices during flaring events. To Koch, this means:
 - A. Taking immediate action in response to unexpected flaring events to bring flare load back within the recovery system capacity.
 - B. Reducing refinery operating rates and severities to eliminate or minimize flaring while responding to significant unexpected events, taking into account other environmental and safety factors.
 - C. To carefully plan and execute infrequent planned events such as unit turnarounds and maintenance of critical refinery components to minimize or, if feasible, eliminate flaring.

3. To establish a process of continuous improvement of flare system operation, including:
 - A. Conducting root cause failure analyses on significant flaring events; and
 - B. Periodically reviewing, evaluating, and updating these flare policies and procedures.

The following sections will summarize Koch's policy regarding each of these items.

- 1. To follow good engineering practices that provide for a well-managed and well maintained flare system as well as the equipment that relieves to the flare system.**

- A. A flare gas recovery system designed and operated to capture most anticipated loads to the flare system.**

The Koch Pine Bend and Corpus West Refineries each has installed and maintains a flare gas recovery system designed to prevent flaring of most streams vented to the flare system. The system at the Pine Bend Refinery, which has a level of excess capacity, is made up of two flare gas recovery compressors that remain operational at all times under normal conditions. The normal base load to the system can be managed so that it can be recovered by one compressor, if necessary. The system at the Corpus West Refinery consists of one flare gas recovery compressor which remains operational at all times under normal conditions. The baseload to the system is managed so that it can be recovered by this compressor under most operating scenarios. Thus, these system designs incorporate good engineering practices in regard to

handling base load. The flare gas recovery system to be installed at the Corpus East Refinery pursuant to the Consent Decree will have a similar design.

B. A management system designed to keep the base load into the flare system within the system's recovery capacity

Along with the recovery capacity, Koch has implemented a process for managing the base load to the system. The process provides that the Refinery Shift Manager (RSM) has responsibility for minimizing the flare system base load relative to the capacity of the recovery system. No individual within the refinery can commence a planned activity that can possibly add significant load to the flare system without first obtaining the approval of the RSM (an RSM is on duty within the refinery 24 hours per day, 7 days per week). Prior to granting approval, the RSM will evaluate current load to the system and determine if the projected load from the requested activity can be recovered. If not, the event will be delayed or other measures will be taken to first decrease flare system load in order to prevent or minimize flaring.

The RSM also is charged with monitoring base load into the flare system on a regular basis. If the load is trending upward such that unexpected flaring occurs, the RSM implements a procedure to determine the reasons for that increased load. This procedure occurs pursuant to a flare system management flowchart which prioritizes the investigation in an effort to quickly identify the source. If the source of increased load is not readily identified, the refinery implements a full flare system audit, evaluating all equipment in the refinery that may

relieve to the flare system to identify possible unexpected sources of flaring.

C. A management system based on good engineering practices designed to minimize, and, if feasible, prevent, unexpected loads to or unexpected failure of the flare system

Over the past two years, the Koch Refineries have been implementing a Reliability Centered Maintenance (RCM) program to ensure proper maintenance of refinery equipment. The RCM process was designed for and first implemented by the airline industry to help ensure against aircraft failure. The process also is common among nuclear power plants. RCM is not as common in other industrial applications, but Koch has selected it as the most effective way to ensure an appropriate level of equipment reliability.

The key to RCM is to identify each refinery system, analyze its function and, in a group setting with many different disciplines represented, determine what events could jeopardize that system's performance. From this process flows a set of priorities based on how critical a given piece of equipment is and a series of strategies for the maintenance of each piece of equipment. These strategies range from periodic inspection to continuous monitoring, to preventive or predictive maintenance at appropriately determined intervals to repair replacement and/or re-engineering of critical refinery components.

Maintenance priorities are determined based on a risk ranking system that considers the likelihood of any given occurrence multiplied by the consequences of the occurrence. In that ranking system, environmental and safety consequences are weighted more heavily than any

other single factor (up to twice as high as any other factor). Thus, this ranking process prioritizes maintenance response and preventive or predictive maintenance on the components critical to good environmental performance.

Another result of the prioritization process is the creation of a critical components list, which is a refinery-wide list of equipment with a high risk ranking. This equipment is specifically identified for more rigorous preventive and/or predictive maintenance. In addition, the work order ranking system is designed to ensure that predictive maintenance procedures are given sufficient priority that they are conducted on a routine basis.

As the RCM process is underway, Koch also is conducting a parallel review of critical operating parameters for each unit. Currently, Koch utilizes OSHA Process Safety Management (PSM) constraints to define critical equipment limitations, ensuring that equipment will be operated within safe limits and minimizing the potential for flaring events. Using these process safety management parameters as a baseline, the Koch RCM team also is in the process of identifying optimal reliability guidelines for the operation of each unit. These reliability parameters will normally be set more conservatively than the PSM limits in an effort to lengthen equipment life and ensure more predictable equipment performance. As they are developed, these guidelines will be incorporated into the control system and will assist operators as they manage the refinery process.

A final component of the RCM process is conducting a root cause analysis of an equipment failure event. This analysis, which is separate from the root cause analysis of flaring events discussed in Section 3.A. below, is necessary to ensure continuous improvement of equipment maintenance strategies.

As in the airline and nuclear industry, the intent of the Koch RCM process is to prevent or minimize unexpected failure. For purposes of this flare policy, the RCM process will help ensure proper maintenance of refinery processes that, if they fail, will vent to the flare system. The RCM process also will help ensure proper maintenance of the flare system itself.

2. To follow good engineering practices and good air pollution control practices during flaring events.

A. Taking immediate action in response to unexpected flaring events to bring flare load back within the recovery system capacity.

As discussed above, Koch has in place a system to manage flare load so as to avoid or minimize flaring and to reduce flare load when it begins trending upward. . When unexpected flaring occurs, the RSM will implement the flare investigation procedure described above with the goal of identifying the source of flaring and reducing flare load back within the recovery capacity, if possible. This is accomplished either by remedying the source of the flare load or reducing, where feasible, load from other sources.

B. Reducing refinery operating rates to eliminate or minimize flaring while responding to significant unexpected events, taking into account other environmental and safety factors.

Most often, the source of an unexpected flaring event will be obvious and typically is associated with some unexpected failure within one of the process units. As discussed above, once the source of the flaring is identified, the refinery implements a process to remedy the source as quickly as possible. This process is more difficult when the system failure is more extensive and the source cannot rapidly be remedied. Koch has in place a decision framework to assist in evaluating the available choices and making a choice that reflects both good engineering practice as well as good air pollution control practice.

The framework is based on the following two priorities:

Koch will first take measures to ensure that its people and its equipment are safe. The goal is to prevent a system failure from becoming worse or even catastrophic. Equipment is designed to relieve to the flare system specifically in order to meet this goal.

Koch will then take measures to minimize environmental impact. The first step will be to determine if an immediate remedy (using 30 minutes as a benchmark) is available. For example if a compressor or heater has shut down, Koch will investigate whether an expedient restart is possible. If an immediate remedy is not available, the RSM will develop and implement a contingency plan. The contingency plan will involve cutting process rates and reducing the severity of operating conditions to reduce gas generation rates, thereby reducing or eliminating the flaring. The plan will focus on rate cuts to the unit that is experiencing difficulty (ultimately stopping just above the unit's

turndown rate, the rate below which the unit must be shut down) as well as rate cuts or processing changes at other units within the refinery with the goal of eliminating flaring as soon as possible. This may be accomplished by reducing overall refinery gas generation rates or making additional gas recovery capacity available. The refinery maintains a matrix of various options for shifting gas plant streams within the refinery to support these operating decisions. This matrix is consulted in order to evaluate possible options for isolating or reducing flow to the unit experiencing difficulty. If such opportunities exist, they will be implemented.

The plan does not normally include the immediate shut down of a unit, as that most often would increase flaring significantly in the short term. This decision must be evaluated as an incident progresses. If an equipment failure can be corrected within a 12 to 24 hour period, it is rarely, if ever, a good idea to shut down a unit. The emissions (and additional flaring) associated with unit shutdown and startup normally will exceed the emissions associated with some continued flaring from a unit operating just above its turndown rate. In addition, good engineering practices and safety concerns dictate that unit shutdown be avoided if possible. By their nature, unit shutdowns and startups are periods of transient operation, posing greater safety concerns and increasing the likelihood of process upsets which could aggravate flaring from the affected unit and/or result in flaring from up- and downstream units.

Nevertheless, if all other steps to eliminate flaring have been implemented, and flaring continues after a 24 hour period, the refinery will consider unit

shutdown as an option. Again, that measure must be carefully weighed in light of the potential safety, environmental and engineering consequences. The nature of the affected process and the difficulty of the associated shutdown and startup procedures must be weighed in this decision. Any decision to continue flaring after the 24 hour period will be made in consultation with members of the local community as well as with local and state regulatory authorities.

C. To carefully plan infrequent planned events such as unit turnarounds and maintenance of critical refinery components to minimize or, if feasible, eliminate flaring

In order to maintain operating units in a safe and efficient operating condition, Koch, as well as most of the refining industry, has implemented the good engineering practice of periodically performing maintenance "turnarounds" on its process units. During a turnaround, process units are shut down so equipment can be opened, cleaned, inspected and repaired. Flaring may occur during shutdown and subsequent startup of these units.

As a typical unit is being shutdown, safety considerations as well as good engineering practice dictates that the unit be vented to the flare gas system. This occurs as the process rates are reduced to the point where the unit reaches a point of unstable operation. Gas recovery equipment must be shut down and further reductions without venting to the flare system may create risk to personnel and equipment. The unit must then be vented to the flare system until all excess process

gasses have been removed. Some process areas require additional gas purging to the flare to cool equipment or to maintain catalyst activity. Further, prior to opening the unit for work, it must be steamed out to remove remaining hydrocarbons and allow for a safe work environment. The flare system exists to safely and properly manage this flow. Essentially the reverse procedure must be followed for unit startup.

The environmental challenge associated with turnaround is to manage the timing and nature of unit shutdown and startup as well as the nature and rate of feed into any given unit so as to minimize the nature and extent of flaring associated the such events. Koch has implemented a plan to accomplish this task.

The following turnaround planning and execution stages are utilized to ensure good air pollution control practices and to minimize flaring activity during shutdown and startup events:

- Scheduling individual unit turnarounds.
- Identifying specific turnaround activities
- Identifying potential environmental impacts of each activity and developing mitigation plans to address adverse impacts.
- Executing unit shutdowns and startups to manage the overall refinery impacts and meet environmental objectives.
- Review of turnaround execution and implementation of improvement for the next turnaround.

The following is a discussion of each of these stages.

Scheduling individual unit turnarounds.

The length of the turnaround cycle for any given unit depends on the type of process unit and individual unit operating history. Koch schedules each process unit turnaround based on a combination of standard industry practices and local knowledge.

During each turnaround period, Koch performs turnarounds on units which have reached or are approaching the end of their respective turnaround cycles. Units are also selected for a particular turnaround based on their impacts on related process units. This ensures that the units remaining online are operating within their processing and environmental constraints.

The unit turnaround schedule is also examined for opportunities to perform periodic maintenance on related process units. This is done by utilizing spare capacity created by the turnaround to get at equipment to perform these activities with reduced environmental impact.

Identifying specific turnaround activities

Once a unit is scheduled for turnaround, a list of maintenance requirements is developed. The list is developed based on previous turnaround history and recent operating data. This ensures that equipment is well maintained and operates reliably between turnarounds.

Identifying potential environmental impacts of each activity and developing mitigation plans and goals to address adverse impacts.

The list of turnaround activities is analyzed for potential environmental impacts. This list includes activities associated with unit shutdown, vessel purging and degassing, preparation for startup and unit startup as well as planned maintenance activities. An environmental mitigation strategy is developed for each activity.

Executing unit shutdowns and startups to manage the overall refinery impacts

Timing of the actual unit shutdowns and startups is coordinated through the RSM to ensure proper environmental management of flaring activity. The RSM adjusts the shutdown

and startup schedules to account for schedule delays and unplanned events which may occur. Schedules are also adjusted based on other activities that may affect flare load so as to maximize the use of the flare gas recovery system and to help meet the flaring control goals.

Review of turnaround execution and implementation of improvement for the next turnaround.

Following each turnaround, plans are reviewed to identify which parts of the plan worked well and which parts need improvement. Review findings are then incorporated into the next turnaround plan.

In addition, inspection information gathered during the turnaround is used to assess operation, maintenance and engineering design practices and to improve these practices for improved operational reliability in the future.

Planned Maintenance On Critical Components

The refinery also performs planned maintenance on critical refinery components at times other than full unit turnaround. Such maintenance, which is contrasted with the need to shut down a component because of an unplanned event (discussed in Section 2B above), will occur pursuant to an established maintenance program based on good engineering practices. In addition, at Corpus West, periodic flare entries are required to repair and replace leaking relief valves. During this operation, the flare gas recovery system must be bypassed.

Flaring may occur during such events as a result of the need to isolate the piece of equipment on which maintenance is being performed. Any such flaring will be pre-evaluated and managed in accordance with the policies discussed above. That is, planned maintenance will be performed only when the refinery can flare consistent with safety and good engineering practices. The maintenance event will be planned carefully to minimize flaring. All feasible measures will be taken to reduce the operating rate of the affected unit and other units' rates will be adjusted to ensure the lowest possible load to the flare system.

The refinery expects such events to be of limited duration (typically less than 24 hours) and to take place only in situations where proper maintenance dictates that the benefit of the work and the associated flaring outweighs the risk of unexpected failure which may result if the work is delayed until the next full unit shutdown.

For example, good engineering practices may dictate that certain components undergo maintenance more frequently than the turnaround schedule of the units to which they belong. While it is prudent to maintain those components according to a proper schedule, it is rarely, if ever, prudent, from an environmental, safety, or engineering standpoint, to bring an entire unit down to accomplish that maintenance.

3. To establish a process of continuous improvement of flare system operation.

A. Conducting root cause failure analyses on significant flaring events

As part of this policy and, in an effort to ensure continued improvement of flare system management, Koch will undertake a Root Cause Failure Analysis (RCFA) of any unplanned significant flaring event. For purposes of this policy, "significant flaring event" is defined as any single event from which SO₂ emissions exceed an applicable permit limit 500 pounds in a 24-hour period and which are not associated with a planned startup, shutdown, or maintenance activity. For any such event, appropriate refinery personnel will meet, conduct the analysis, identify and implement any feasible corrective actions to prevent recurrence of the event. Koch shall provide a summary of all "significant Hydrocarbon Flaring Event(s)" in its quarterly excess emissions report to the appropriate State agency.

B. Periodically reviewing, evaluating, and updating these flare policies and procedures.

Koch is committed to ensuring ongoing optimal management of its flare system. Part of that effort will be to review this policy on an annual basis with key operations and maintenance

personnel to ensure continued adherence to the policy and to make any needed improvements to the policy.

ATTACHMENT 3

RCRA CONSENT AGREEMENT AND FINAL ORDER

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5

IN THE MATTER OF:)	Docket No. RCRA-5- 2000 - 010
)	
KOCH PETROLEUM GROUP, L.P.)	CONSENT AGREEMENT
12555 U.S. HIGHWAY 55)	AND FINAL ORDER
ROSEMOUNT, MINNESOTA 55068)	
)	
EPA ID No.: MND 000 686 071)	
)	
Respondent.)	
_____)	

I. PREAMBLE

On this date, an administrative Complaint and Proposed Compliance Order is simultaneously being filed in this matter pursuant to Section 3008(a) of the Resource Conservation and Recovery Act, as amended (RCRA), 42 U.S.C. § 6928(a), and the Consolidated Rules of Practice Governing the Administrative Assessment of Civil Penalties, Issuance of Compliance or Corrective Action Orders, and the Revocation, Termination or Suspension of Permits, 40 C.F.R. Part 22, as revised at 64 Fed. Reg. 40138 (July 23, 1999) (Consolidated Rules). The Complainant is, by lawful delegation, Chief of the Enforcement and Compliance Assurance Branch, Waste, Pesticides and Toxics Division, Region 5, United States Environmental Protection Agency (EPA). The Respondent is Koch Petroleum Group, L.P.

II. STIPULATIONS

The Parties, desiring to settle this action, enter into the following stipulations:

Preliminary Statement

1. Respondent is simultaneously being served with a copy of the administrative Complaint in this matter. The Complaint alleges violations of the authorized Minnesota hazardous waste program in Counts 1 through 5, and 16 through 19; violations of Federal statutes and regulations pertaining to listed F037 waste in Counts 6 through 15; and violations of Federal RCRA Air Emission Standards for Tanks, Surface Impoundments, and Containers in Counts 12 and 19. The Complaint is incorporated herein by reference.

2. Respondent is Koch Petroleum Group, LP, which is and was at all times relevant to this Complaint, along with its corporate predecessor Koch Refining Company, the owner and operator of a facility located at 12555 U.S. Highway 55, Rosemount, Minnesota, 55068 (the Facility). Koch Petroleum Group, LP and Koch Refining Company are referred to collectively herein below as "Respondent."

3. Respondent is a "person" as defined in Section 1004(15) of RCRA, 42 U.S.C. § 6903(15), Minnesota (MN) Rules Part

7045.0200, subpart 66, and 40 C.F.R. § 260.10.

4. The Complaint proposes that Respondent be assessed a civil penalty of \$3,500,000 calculated in accordance with Sections 3008(a) and 3008(g) of RCRA, and with reference to the "RCRA Civil Penalty Policy" (October 1990) for the violations alleged in the Complaint.

5. As a result of information exchanged during settlement negotiations, EPA and Respondent agree that resolution of this matter through entry of this Consent Agreement and Final Order (CAFO) is an appropriate means of resolving this matter and have agreed to enter into this CAFO.

6. This CAFO sets forth the agreements between EPA and Respondent that are intended to fully resolve the allegations of the Complaint; Respondent will not be required to file an Answer to the Complaint.

7. This CAFO is issued to conclude the administrative penalty matter initiated by the EPA administrative Complaint. The Complaint was issued for all of the RCRA violations for which Complainant seeks enforcement as identified during inspections of Respondent's facility during June 1998 and May 1999. The parties intend to incorporate the terms of this CAFO into a Consent Decree which is being negotiated between Koch and EPA, in order

to obtain judicial confirmation and enforceability for the schedules and injunctive relief set forth in this CAFO. Nothing shall prevent the parties from altering in such Consent Decree the scope of release for these violations.

General Terms of Settlement

8. Respondent admits that EPA has jurisdiction over the matter, neither admits nor denies the findings of fact and conclusions of law in the Complaint, agrees that settlement of this action is in the best interests of the parties and in the public interest, and consents to the terms of this CAFO as set forth herein.

9. Respondent hereby waives its right to a judicial or administrative hearing on any issue of law or fact set forth in the Complaint or this CAFO, and waives any and all rights to appeal this settlement and/or CAFO.

10. Respondent agrees to implement the Compliance Order included below as part of this CAFO, and certifies that it is now otherwise in compliance with the requirements of RCRA set forth in the Complaint.

11. If Respondent fails to comply with any provision contained in this CAFO, Respondent waives any rights it may possess in law or equity to challenge the authority of EPA to

bring a civil action in the appropriate United States District Court to compel compliance with the CAFO and/or to seek an additional penalty for the noncompliance with the CAFO.

12. Pursuant to Sections 3008(a) and 3008(g) of RCRA, and based on the foregoing, the nature and seriousness of the violations alleged in the Complaint, the potential harm to human health and the environment, Respondent's willfulness/negligence or lack thereof and history of noncompliance, the ability of Respondent to pay penalties, any good faith efforts by Respondent to comply, information exchanged by the parties, consideration of the steps Respondent took and has agreed to take to achieve compliance, the fact that Respondent had settled similar violations with Minnesota Pollution Control Agency (MPCA), Respondent's prompt and cooperative resolution of this penalty matter, and other relevant factors, EPA has determined that an appropriate civil penalty to settle this action is in the amount of \$3,500,000. Complainant accordingly assesses a civil penalty in the amount of \$3,500,000.

13. Respondent agrees to the assessment of the civil penalty set forth in this CAFO for the violations alleged in the Complaint. The parties anticipate that payment of the penalty will occur before November 15, 2000 under provisions of the

Consent Decree under negotiation.

Penalty Payment

14. If the penalty is not paid by November 15, 2000 under a federal district court Consent Decree, then by no later than November 30, 2000, Respondent shall submit a cashier's or certified check, to the order of the "Treasurer of the United States of America," in the amount of THREE MILLION FIVE HUNDRED THOUSAND DOLLARS (\$3,500,000). The check shall be mailed to:

U.S. EPA, Region 5, Regional Finance Office
P.O. Box 70753
Chicago, Illinois 60673

The name of the Respondent and the Docket Number of this proceeding shall be clearly marked on the face of the check. Interest and late charges shall be paid as specified as below.

15. A transmittal letter, indicating Respondent's name, complete address, and this case Docket Number must accompany the payment. Respondent shall send a copy of each check and transmittal letter to:

- 1) Regional Hearing Clerk
U.S. Environmental Protection Agency, Region 5
77 West Jackson Boulevard (MF-19J)
Chicago, Illinois 60604;
- 2) Ivonne Vicente, Compliance Section
Enforcement and Compliance Assurance Branch
Waste, Pesticides and Toxics Division
U.S. Environmental Protection Agency, Region 5
77 West Jackson Boulevard (DE-9J)
Chicago, Illinois 60604; and

3) Andre Daugavietis
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 5
77 West Jackson Boulevard (C-14J)
Chicago, Illinois 60604.

16. Respondent's failure to timely comply with any material and substantial provision of this CAFO shall render the entire unpaid portion of the assessed penalty of \$3,500,000 immediately due and payable, together with all accrued interest. Such failure may also subject Respondent to a civil action pursuant to Section 3008(c) of RCRA to collect penalties for any noncompliance with the Order (as well as injunctive relief) and any unpaid portion of the assessed penalty, together with interest, handling charges and nonpayment penalties as set forth below. In any such collection action, the validity, amount and appropriateness of this CAFO or the penalty and charges assessed hereunder shall not be subject to review.

Late Payment Provisions

17. Pursuant to 31 U.S.C. §§ 3717 and 3731, Respondent shall pay interest and penalties on debts owed to the United States and a charge to cover the costs of debt collection, including processing and handling costs and attorneys fees. If the civil penalty is not paid pursuant to the terms of this CAFO,

Respondent shall pay the following amounts:

A. **Interest.** Any unpaid portion of a civil or stipulated penalty shall bear interest at the rate established by the Secretary of the Treasury pursuant to 31 U.S.C. § 3717(a)(1). Interest will therefore begin to accrue on a civil or stipulated penalty if it is not paid by the last date required. Interest will be assessed at the rate of the United States Treasury tax and loan rate in accordance with 4 C.F.R. § 102.13(c).

B. **Monthly Handling Charge.** Respondent shall pay a late payment handling charge of \$20.00 on any late payment, with an additional charge of \$10.00 for each subsequent 30-day period over which an unpaid balance remains.

C. **Non-Payment Penalty.** On any portion of a civil or stipulated penalty more than ninety (90) days past due, Respondent shall pay a non-payment penalty of six percent (6%) per annum, which will accrue from the date the penalty payment became due and is not paid. This non-payment is in addition to charges which accrue or may accrue under Subsections A and B, above.

General Provisions

18. Nothing in this CAFO shall relieve Respondent of the duty to comply with all applicable provisions of RCRA and other Federal, state or local laws or statutes.

19. Respondent's compliance with this CAFO shall constitute compliance with applicable provisions of RCRA and other Federal, state or local laws or statutes.

20. Nothing in this CAFO shall be construed to be a ruling on, or determination of, any issue related to any federal, state

or local permit.

21. Nothing in this agreement shall be construed as prohibiting, altering or in any way limiting the ability of EPA to seek any other remedies or sanctions available by virtue of Respondent's violation of this agreement or of the statutes and regulations upon which this agreement is based, or for Respondent's violation of any applicable provision of law, other than the specific matters resolved herein.

22. Notwithstanding any other provision of this CAFO, EPA may bring an enforcement action pursuant to Section 7003 of RCRA, or other statutory authority, if any handling, storage, treatment, transportation or disposal of solid or hazardous waste may present an imminent and substantial endangerment to human health or the environment.

23. The penalty specified herein shall represent civil penalties assessed by EPA and shall not be deductible for purposes of Federal taxes.

24. This CAFO represents a full and final settlement of any and all claims by EPA against Respondent arising from the Complaint. The Complaint was issued for all of the RCRA violations for which Complainant seeks enforcement as identified during inspections of Respondent's facility during June 1998 and

May 1999.

25. The information required to be maintained or submitted pursuant to this CAFO is not subject to the Paperwork Reduction Act of 1980, 44 U.S.C. §§ 3501 et seq.

26. This CAFO shall be binding upon all Parties to this action, and their successors and assigns. The undersigned representative of each Party to this CAFO certifies that he or she is duly authorized by the Party whom he or she represents to enter into the terms and bind that Party to them.

27. Respondent shall give notice and a copy of this CAFO to any successor in interest prior to any transfer of ownership or operational control of the Facility.

28. Respondent waives any right it may have pursuant to 40 C.F.R. § 22.08 to be present during discussions with, or to be served with and reply to, any memorandum or communication addressed to the Director, Waste, Pesticides and Toxics Division, or his superiors, where the purpose of such discussion, memorandum or communication is to persuade such an official to accept and issue the CAFO.

29. Failure to comply with any provision of this CAFO or Compliance Order shall subject Respondent to injunctive relief in U.S. District Court and liability for a civil penalty of up to

Twenty-Seven Thousand Five Hundred Dollars (\$27,500) for each day of continued noncompliance, pursuant to Section 3008(c) of RCRA, 42 U.S.C. § 6928(c), as amended.

30. Each party shall bear its own costs, attorney fees and disbursements in this action.

31. This CAFO constitutes the entire agreement and settlement between the parties.

32. Respondent and EPA agree to issuance and entry of the accompanying CAFO.

33. This CAFO shall become effective on the date it is signed by the Director, Waste, Pesticides and Toxics Division.

In the Matter of: Koch Petroleum Group. L.P.

III. COMPLIANCE ORDER

34. The foregoing Consent Agreement is Hereby Stipulated, Agreed, and Approved for Entry.

35. Respondent shall, immediately upon the effective date of this CAFO (except as otherwise specified in this Order), cease all treatment, storage, or disposal of any hazardous waste except such treatment, storage, or disposal that is in compliance with the schedule, procedures, interim plans or requirements specified in this Order, the applicable standards for hazardous waste treatment, storage, and disposal facilities, and the Final Permit issued by MPCA for the Facility.

36. Respondent shall comply with the schedule, procedures, interim plans and requirements specified in this Order and shall otherwise, immediately upon the effective date of this CAFO (except as otherwise specified in this Order), achieve and maintain compliance with the standards applicable to generators of hazardous waste..

37. Respondent shall, within thirty (30) days of the effective date of this CAFO, submit a written closure and post-closure plan in accordance with 40 C.F.R. § 264.110 through 264.120 to EPA, with a copy to MPCA, for: the two piles of F037

containing coke materials located in the vicinity of the coker ponds ("the Managed Piles") as well as the areas where the piles have been stored; and the lower and upper washpads.

38. Respondent shall, within thirty (30) days of the effective date of this CAFO, submit a written closure and post-closure plan in accordance with MN Rules 7045.0486 through 7045.0492 to MPCA, with a copy to EPA, for the fire training collection basin.

39. Respondent shall, by no later than July 1, 2000, submit a written closure and post-closure plan in accordance with MN Rules 7045.0486 through 7045.0492 (40 C.F.R. § 264.110 through 264.120) to MPCA, with a copy to EPA, for closure of the Facility's B5 basin to be completed by no later than December 31, 2001.

40. Respondent certified on November 15, 1999, in accordance with its hazardous waste facility permit MN0006886071 and MN Rules Part 7001.0070 and 7001.0540, that the coker ponds at the Facility were closed in accordance with the MPCA-approved closure plan and additional closure workplans described therein. Respondent's certification that final closure of the coker ponds has been accomplished in accordance with the MPCA-approved closure plan is subject to MPCA approval. Respondent certifies

that final closure of the coker ponds has been accomplished in accordance with the "Coker Pond Closure Plan, Contingent Closure Plan, and Contingent Post-Closure Plan" dated October 28, 1998.

41. Upon receiving MPCA approval of any written closure plan, or any other plan or schedule, for any RCRA units managing listed or characteristic waste for which MPCA has an authorized hazardous waste program, Respondent shall implement the approved closure plan in accordance with the specifications and schedule contained therein, as modified by MPCA. In the event that the RCRA unit manages F037 waste and that EPA is the primary agency with authority for F037 waste, upon receiving EPA approval of any written closure plan, or any other plan or schedule, Respondent shall implement the approved closure plan in accordance with the specifications and schedule contained therein, as modified by EPA.

42. Recognizing that EPA considers that certain materials currently stored by Respondent at its Facility in the Managed Piles constitute listed hazardous wastes; and that Respondent considers that these materials are not listed hazardous wastes, but are product coke suitable for sale as fuel; and recognizing that Respondent has agreed to manage these materials as if they were listed hazardous wastes and store them in a manner

consistent with Paragraphs 49, 50 and 51 of this CAFO, in order to reach agreed settlement of this matter; Respondent may submit a petition to the agency with primary authority (in accordance with 40 C.F.R. §§ 260.20 and 260.22) to exclude (or "de-list") from the listing of hazardous wastes under Subpart D of 40 C.F.R. Part 261, the following materials stored at its Facility: (1) the Managed Pile in the vicinity of the coker ponds that currently stores materials to be managed as listed F037 waste (approximate volume 10,000 cubic yards); and (2) the Managed Pile in the vicinity of the coker ponds that currently stores materials to be managed as listed F037 waste mixed with product coke (approximate volume 40,000 cubic yards).

43. Respondent shall submit a copy of any de-listing petition subject to this CAFO to EPA and MPCA to ensure that both Agencies are aware of the petition and its contents.

44. The timing of the de-listing process shall be as set forth in Attachment A to this CAFO, and interim milestone dates as set forth in the Attachment may be modified in writing by Koch and the agency with primary jurisdiction over the de-listing petition at the time of the dates to be modified.

45. If, at any time after the effective date of this CAFO, Respondent does not comply with its interim milestone deadlines

regarding the de-listing petition as set forth in Attachment A or as modified by the agency with primary authority at the time, or if Respondent elects to withdraw its petition, Respondent shall ship all of the material from the Managed Piles to a designated facility or facilities suitable for the disposal of F037 listed hazardous wastes (as defined at 40 C.F.R. § 260.10) or otherwise recycle the materials on site in a manner consistent with regulations applicable to F037 listed hazardous waste.

Respondent shall complete such shipments or other disposition within sixty (60) days of the event triggering the requirement, and thereafter cease storing any such materials at its Facility. Respondent shall ensure that such shipments are in full compliance with RCRA requirements, including manifests, if the material is managed off-site.

46. Beginning no later than December 31, 2001, unless the petition has been granted (or unless EPA and Respondent have jointly agreed to amend this final milestone date, in which case the amended date shall control), Respondent shall ship all of the material from the Managed Piles to a designated facility or facilities suitable for the disposal of F037 listed hazardous wastes (as defined at 40 C.F.R. § 260.10) or otherwise recycle the materials on site in a manner consistent with regulations

applicable to F037 listed hazardous waste. Respondent shall complete such shipments or other disposition by no later than March 1, 2002 (or 60 days from a modified final milestone date), and cease storing any such materials at its Facility. Respondent shall ensure that such shipments are in full compliance with RCRA requirements, including manifests, if the material is managed off-site.

47. If before December 31, 2001, the petition is denied by the agency with RCRA authority over F037 wastes at the time, and the denial becomes final, Respondent shall immediately ship all of the material from the Managed Piles to a designated facility or facilities suitable for the disposal of F037 listed hazardous wastes (as defined at 40 C.F.R. § 260.10) or otherwise manage and dispose of the materials in a manner appropriate for F037 listed wastes, subject to approval of the agency with RCRA authority over F037 wastes at the time. If before December 31, 2001, the de-listing petition is denied, Respondent may exercise any appeal rights it may have under law or regulation, and if Respondent appeals the denial it may begin the shipments or other disposition of the materials as of December 31, 2001 (or a modified milestone date). Respondent shall complete the shipments or other disposition within sixty (60) days of the

petition denial becoming final (or by March 1, 2002, if it has filed an appeal after denial of the petition) and cease storing any such materials at its Facility. If the material is managed off-site, Respondent shall ensure that such shipments are in full compliance with RCRA requirements applicable to shipments of F037 wastes, including manifests.

48. EPA has been the primary agency with authority over F037 listed hazardous wastes, but arrangements are pending under which EPA would delegate authority over F037 listed hazardous wastes to MPCA. The petition to exclude the Managed Piles from the listing of hazardous wastes shall be submitted to the agency (EPA or MPCA) which has primary authority over F037 listed wastes. A copy of the petition shall be submitted to the other agency. The Parties contemplate that even if the petition is originally submitted to EPA, it will be transferred to MPCA at such time, if any, that MPCA received delegated authority to regulate F037 listed hazardous wastes. If prior to Respondent's full compliance with the requirements of this Order, MPCA receives final authorization from EPA to administer and enforce Minnesota's hazardous waste program for F037 waste, Respondent shall submit any plans, petitions or other documents under this Order relating to F037 waste to MPCA for administration by MPCA.

Respondent shall submit a copy of all such documents to EPA. Upon such authorization by MPCA, EPA shall retain sole authority to revise any deadlines set forth in this CAFO (with the exception of the interim milestone dates referenced in Par. 44 and Attachment A), and Respondent shall request any extensions in writing to EPA, together with the reason(s) for such request and a proposed alternative deadline.

49. For the two Managed Piles located in the vicinity of the coker ponds at the Facility, Respondent certifies that it has installed, and shall continue to operate and maintain a run-on and run-off system and control wind dispersal in accordance with 40 C.F.R. § 264.251(g) through (j).

50. For the two Managed Piles located in the vicinity of the coker ponds at the Facility, Respondent shall continue to conduct weekly inspections and inspections after storms to detect deterioration, malfunctions, or improper operation of the run-on and run-off control systems and proper functioning of the wind dispersal control system pursuant to 40 C.F.R. § 264.254(b).

51. For the two Managed Piles and the areas where the piles were located, the B5 basin, lower and upper washpads, and the fire training collection basin, Respondent certifies that it has amended its financial test to comply with the financial assurance

requirements of closure and post-closure in accordance with MN Rules 7045.0504 and 7045.0508 (40 C.F.R. §§ 264.143 and 264.145).

52. Respondent shall notify EPA in writing upon achieving compliance with this Order, and with each of above paragraphs 37, 38, 39, 45, 46, 47 individually, within fifteen (15) calendar days after the date compliance is achieved.

53. If any required action has not been taken or completed in accordance with any requirement of this Order, within ten (10) calendar days after the due date set forth in this Order, Respondent shall notify EPA of the failure, the reason for the failure, and the proposed date for compliance.

IV. STIPULATED PENALTIES FOR MANAGED PILE STORAGE

54. In the event that the Managed Pile materials referenced in Paragraph 42, above, are not de-listed by December 31, 2001 (or a modified final milestone date), or a denial of Respondent's de-listing petition becomes final before such date, Respondent shall be liable for stipulated penalties of \$1,430 per day to the United States.

55. Stipulated penalties under this section shall accrue from the earliest of: 1) December 31, 2001 (or a modified final milestone date); 2) the date of any interim milestone deadline

set forth in Attachment A (as modified) that Koch does not comply with; 3) the date a withdrawal or denial of the de-listing petition becomes final (subject to the appeal provisions in Par. 47), or 4) the date of this CAFO if no de-listing petition is filed; and shall continue to accrue until Respondent certifies that the Managed Pile materials have been fully removed or otherwise disposed. The stipulated penalties will be waived if the condition set forth in paragraph 57, below is met.

56. Respondent shall pay these stipulated penalties within fifteen (15) days of receipt of written demand by EPA for such penalties after such penalties are accrued. Method of payment shall be in accordance with the provisions of Paragraphs 14 through 17, above. Interest and late charges shall be paid as stated therein.

57. If the Managed Pile materials referenced in Paragraph 42, above, are de-listed by December 31, 2001 (or a modified final milestone date), Respondent shall not be liable for stipulated penalties applicable under this section.

VI. SUBMITTALS AND NOTIFICATIONS

58. All reports, plans, submissions, and notifications to EPA required by this Order shall be submitted to:

U.S. EPA, Region 5
Waste, Pesticides and Toxics Division
Enforcement and Compliance Assurance Branch
Attention: Ivonne Vicente (DE-9J)
77 West Jackson Boulevard
Chicago, Illinois 60604

59. Respondent shall submit a copy of all documents and correspondence regarding this CAFO to MPCA at the address specified below.

60. The parties plan to have the terms of this CAFO incorporated into a federal district court consent order or decree. This CAFO shall continue in full force and effect whether or not its terms are so incorporated.

61. Whenever, under the terms of this CAFO, notice is required to be given or a document sent to Respondent or MPCA, it shall be directed to the individuals at the addresses specified below:

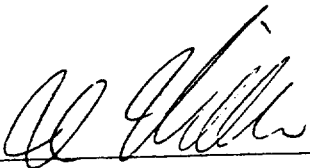
To Respondent:

Jeff C. Wilkes, Vice President
Koch Petroleum Group, L.P.
P.O. Box 64596
Saint Paul, Minnesota 55164

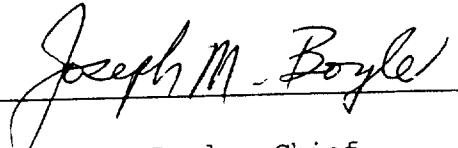
To MPCA:

Thomas Townsend
Minnesota Pollution Control Agency
520 Lafayette Road N.
Saint Paul, Minnesota, 55155-4194.

The terms of the forgoing Consent Order, including Compliance Order are stipulated and agreed to by the Parties as follows:

By:  Date: 9/24/00, 2000

Jeff C. Wilkes, Vice President
Koch Petroleum Group, L.P.
Respondent

By:  Date: August 30, 2000

Joseph M. Boyle, Chief
Enforcement and Compliance Assurance Branch
Waste, Pesticides and Toxics Division
Complainant

RCRA-5- 2000-010

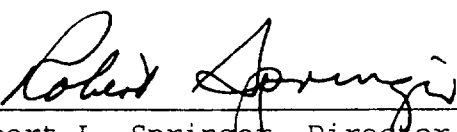
IN THE MATTER OF:
Koch Petroleum Group, L.P.
12555 U.S. Highway 55
Rosemount, Minnesota 55068

FINAL ORDER

The foregoing Consent Agreement is hereby approved and incorporated by reference into this Final Order. The Respondent, Koch Petroleum Group, L.P., is hereby ORDERED to comply with all of the terms of the foregoing Consent Agreement, including the terms of the Compliance Order, effective immediately upon filing of this Consent Agreement and Final Order with the Regional Hearing Clerk. This Order disposes of this matter pursuant to 40 C.F.R. §§ 22.18 and 22.31 [64 Fed. Reg. 40138 (July 23, 1999)].

Dated:

Aug. 30, 2000


Robert L. Springer, Director
Waste, Pesticides and Toxics Division
U.S. Environmental Protection Agency,
Region 5

RCRA-5- 2000-010

Attachment A

KOCH PETROLEUM GROUP, L.P., CONSENT AGREEMENT AND FINAL ORDER

De-listing Petition Schedule

This schedule is to be implemented under paragraph 44 of the CAFO. The interim milestone dates set forth in this Attachment may be modified in writing by Koch and the agency with primary jurisdiction over the de-listing petition at the time of the dates to be modified. If Koch has requested, with good cause, a modified interim milestone deadline and the agency with primary jurisdiction at the time approves the modification within 30 days after the deadline has passed, the modified date shall become the effective interim milestone date under this schedule. The final milestone date may only be modified by EPA and Koch jointly amending the CAFO in writing.

Interim Milestone Dates:

May 15, 2000	Koch submits Sampling and Analysis Plan
July 1, 2000	MPCA approves Sampling and Analysis Plan
Aug. 1, 2000	Koch submits Draft Air Model, Risk Evaluation, and Statistical Comparison Protocol
Oct. 1, 2000	MPCA approves Draft Air Model, Risk Evaluation, and Statistical Comparison Protocol
Oct. 1, 2000	Koch submits analytical results
Nov. 1, 2000	MPCA approves lab results
Jan\ 15, 2001	Koch submits results of modeling
April 15, 2001	MPCA approves modeling results
May 15, 2001	Koch submits materials handling plan, records
June 15, 2001	MPCA approves materials handling, records
July 1, 2001	Koch submits complete petition
Sept 1, 2001	Public comment period begins
Oct 15, 2001	Public comment period ends
Nov 30, 2001	MPCA staff respond to comments and prepare recommendation

Final Milestone Date:

Dec 31, 2001 The de-listing petition process shall be completed
by no later than December 31, 2001.

CERTIFICATE OF SERVICE

I hereby certify that I delivered a copy of the foregoing Complaint and Consent Agreement and Final Order, to the persons designated below, on the date below, by depositing it in the U.S. Mail, certified mail, return receipt requested, postage prepaid, at Chicago, Illinois, in an envelope addressed to:

Mr. Jeff C. Wilkes, Vice President
Koch Petroleum Group, L.P.
P.O. Box 64596
Saint Paul, Minnesota 55164-0596

and sent copies by first class mail to:

Jon Bloomberg, Esq.
Koch Petroleum Group, L.P.
P.O. Box 64596
Saint Paul, Minnesota 55164-0596

and

Mr. Thomas Townsend
Minnesota Pollution Control Agency
Metro District, Major Facilities Section
520 Lafayette Road North
Saint Paul, Minnesota, 55155-4194.

I have further filed the original of the Complaint and Consent Agreement and Final Order and this Certificate of Service in the Office of the Regional Hearing Clerk, U.S. EPA, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604 on the date below.

Dated this 31st day of August, 2000.

Kimberly D. Houston

Secretary, Enforcement and Compliance Assurance Branch
U.S. EPA, Region 5

RCRA-5- 2000-0101

[docket] CIVIL/CRIMINAL [vfmadr]
 3. Docket Docketing [ADDR]
 Processing form: Checks Addressees

Docket # : 0:00-cv-2756 ATYADM
 Short Title: USA v. Koch Petroleum Group
 Type: cv - Judge: Magnuson Magistrate: Nelson

-----Event-----Action-----Relief-----Trans #-----
 labels - - - - - | - - - - - | 1340819
 **** Form: ADDRESS LABELS ONLY ****
 ***** party Direct Addressees in Case: 0:00-cv-02756 *****

Ord	Name	Term
-- 1.	Schiffer	Lois <i>NOT ADMITTED</i>
-- 2.	Shawley	Dianne <i>NOT ADMITTED</i>
-- 3.	Siekert	Friedrich <i>CARRIER</i>
-- 4.	Jackson	James <i>NOT ADMITTED</i>
-- 5.	McAuliffe	Mary <i>MAILED</i>
-- 6.	Lawley	Dianne <i>MAILED</i>

[A]cc, [S]lct, [E]vry, [C]lr, [I]ns, [M]ore, [U]p/[D]n, [N]x/[P]v, [Q]uit
 total: 7 selected: 0 current: 1 :

[docket] CIVIL/CRIMINAL [vfmadr]
 3. Docket Docketing [ADDR]
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Docket # : 0:00-cv-2756 ATYADM
 Short Title: USA v. Koch Petroleum Group
 Type: cv - Judge: Magnuson Magistrate: Nelson

-----Event-----Action-----Relief-----Trans #-----
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 **** Form: ADDRESS LABELS ONLY ****
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Ord	Name	Term
-- 7.	Tester	Peter <i>MAILED</i>

JAMES MAHONEY - KOCH PETROLEUM - MAILED

[A]cc, [S]lct, [E]vry, [C]lr, [I]ns, [M]ore, [U]p/[D]n, [N]x/[P]v, [Q]uit
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*NOT SCANNED OR FAXED.
 COPIES MAILED TO COUNSEL.
 M.C.*

66

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF OKLAHOMA

UNITED STATES OF AMERICA,
ex rel., WILLIAM I. KOCH and
WILLIAM A. PRESLEY,

Plaintiffs,

KOCH INDUSTRIES, INC.; KOCH
EXPLORATION, INC.; KOCH
GATHERING SYSTEMS, INC.; and
KOCH SERVICE, INC.,

Defendants.

Case No. 91-CV-763-K

FILED
IN OPEN COURT
DEC 23 1999

Phil Lombardi, Clerk
U.S. DISTRICT COURT
NORTHERN DISTRICT OF OKLAHOMA

VERDICT FORM NO. 1

(Alleged False Claims Prior to October 27, 1986)

1. As to alleged false claims regarding Government leases during the period from September 30, 1985 through October 26, 1986, we, the jury, find in favor of: *(check one)*

☒ Plaintiffs

☐ Defendants

If you find in favor of Plaintiffs on these claims, complete the remainder of the Form.

If you find in favor of Defendants on these claims, **STOP**, proceed to the end of this Form, sign and date the Form.

2. We, the jury, find that the total number of false claims during the period from September 30, 1985 through October 26, 1986 was 3981.

3. We, the jury, find that during the period from September 30, 1985 through October 26, 1986, as a result of the false claims found in Question 2 above, actual damages should be assessed in the total sum of \$ 137,822.22.

12-23-99
Date

Page 1 of 3

John Middleton
Foreperson

United States District Court)
Northern District of Oklahoma) SS

I hereby certify that the foregoing
is a true copy of the original on file
in this court.

Phil Lombardi, Clerk

By J. W. [Signature]
Deputy

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3. We, the jury, find that the total number of instances in which Defendants either made false claims, reverse false claims, or both, during the period from October 27, 1986 through April 30, 1989, is 20,606.

4. We, the jury, conclude that of those false claims or reverse false claims:

A. 6987 were only false claims and not reverse false claims

B. 13,435 were only reverse false claims and not false claims

C. 184 were both false claims and reverse false claims

20,606 Total (of A, B, and C)

Please note that the total you reach in answer to Question No. 4 must equal the figure you inserted in answer to Question No. 3.

5. We, the jury, find that during the period October 27, 1986 through April 30, 1989, as a result of those false claims or reverse false claims found on Government leases, actual damages should be assessed in the total sum of \$ 415,682.34.

6. We, the jury, find that for the period October 27, 1986 through April 30, 1989, the portion of the actual damages we have awarded in Question No. 5 above attributable to false claims or reverse false claims is as follows:

A. 241,889.94 of the actual damages were due to false claims that were not reverse false claims;

B. 170,607.36 of the actual damages were due to reverse false claims that were not false claims;

C. 3,185.04 of the actual damages were due to instances that were both false claims and reverse false claims.

\$ 415,682.34 Total (of A, B, and C)

Please note that the total you reach in answer to Question No. 6 must equal the total damages that you awarded in answer to Question No. 5.

12-23-99
Date

John Middleton
Foreperson

65

United States District Court
Northern District of Oklahoma) SS
I hereby certify that the foregoing
is a true copy of the original on file
in this court.

Phil Lombardi, Clerk

By J. Wiederholt
Deputy

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF OKLAHOMA

UNITED STATES OF AMERICA,)
ex rel., WILLIAM I. KOCH and)
WILLIAM A. PRESLEY,)
)
Plaintiffs,)
)
vs.) No. 91-CV-763-K
)
KOCH INDUSTRIES, INC, et al.,)
)
Defendants.)

ORDER

FILED
JUL 07 2000
Phil Lombardi, Clerk
U.S. DISTRICT COURT

Before the Court is the motion of the defendants for judgment as a matter of law ("JMOL"). Defendants have actually filed two such motions. The first (#662) was filed November 8, 1999, at the conclusion of plaintiffs' case in chief, and the second (#695) was filed December 9, 1999, at the conclusion of the evidence. By order of December 10, 1999 (#697), the Court denied the first motion, solely on the ground that the motion only addressed plaintiffs' evidence, and the Court wished to consider the evidence as a whole. The Court reserved the right to revisit all arguments made in the first motion. In the second motion, defendants have expressly reasserted arguments made in the first motion. See #695 at 1. Accordingly, the present order addresses arguments made in both motions. The parties have made subsequent filings discussing recent authority from the Tenth Circuit Court of Appeals and the United States Supreme Court which has issued since the initial round of briefing. The Court has also considered these filings.

Judgment as a matter of law is warranted only if the evidence

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points but one way and is susceptible to no reasonable inferences supporting the party opposing the motion. This Court may not weigh evidence, judge witness credibility, or challenge the factual conclusions of the jury. Judgment as a matter of law in favor of the moving party is appropriate only if there is no legally sufficient evidentiary basis with respect to a claim or defense under the controlling law. The Court considers the evidence, and any inferences drawn therefrom, most favorably to the non-moving party. Deters v. Equifax Credit Info. Services, 202 F.3d 1262, 1268 (10th Cir.2000).

This is an action based upon the qui tam provisions of the False Claims Act ("FCA"). The jury concluded that defendants had made a total of 3,981 false claims during the period from September 30, 1985 through October 26, 1986 (actual damages \$137,822.22) and a combined total of 20,606 false claims, reverse false claims or both, during the period from October 27, 1986 through April 30, 1989 (actual damages \$415,682.34). If the present motion is not granted, a penalty phase remains during which this Court will consider imposition of a civil penalty of not less than \$5,000 or more than \$10,000 for each violation. See 31 U.S.C. §3729(a).

In pretrial rulings in this case by Magistrate Judge Joyner, and adopted by the undersigned, the Court ruled that the number of potential FCA violations would be determined by the number of individual leases on an MMS-2014 (a form required to be submitted to the Minerals Management Service), Osage royalty report or monthly check stub when defendants reported and paid for less oil

than they actually took from that lease during the previous month. In doing so, the Court rejected plaintiffs' argument that the appropriate means of calculation was the number of false run tickets, tank tables and meter correction factors.

Subsequently, the Court further ruled that (1) reverse false claims (now codified in 31 U.S.C. §3729(a)(7)) were not actionable prior to the 1986 FCA amendments, but (2) plaintiff had stated a viable theory of direct false claims under 31 U.S.C. §3729(a)(1). The trial proceeded on both theories, and plaintiffs prevailed on both theories. Defendants first contend, as to direct false claims, that plaintiffs have failed to demonstrate a "claim" as required by §3729(a)(1).

In essence, defendants argue that under the trial evidence, the MMS-2014 was not a prerequisite to the obtaining of oil, i.e., that plaintiffs did not establish "but for" causation, which defendants contend case authority requires. Defendants assert that the MMS-2014 merely reports on oil which has already been transferred and therefore could not be the "cause" of that transfer (Defendants' Reply, #716 at 56).

In response, plaintiffs remark on what they perceive as the oddity that, under defendants' theory, "Koch somehow managed to obtain oil off leases the Government owned (beneficially or legally) without ever requesting it, demanding it or obtaining any approval to take it." (Plaintiffs' Response, #710 at 50). Indeed, plaintiffs argued in response to defendants' initial motion that if the Court were to adopt defendants' argument in this regard, the

Court would have to rescind its previous rejection of plaintiff's contention that the documents constituting false claims should have been the run tickets, strapping tables and meter proving reports. (#678 at 22 n.3).

Defendants dismiss this contention, arguing that run tickets also merely report on oil which has already been transferred. The Court does not share defendants' confidence. Testimony was elicited at trial that run tickets were required before oil was transferred. In this sense, defendants are making a "be careful what you ask for" argument. The Court has not calculated a combined total for run tickets, strapping tables and meter proving reports involved in this litigation, but it is clear that a jury verdict which found each of these items to be false could result in penalties in the billions of dollars.

The issue as presented is close, but the Court finds plaintiffs' theory of "false certification" is sufficient to sustain the jury's verdict as to the (a)(1) claims. That is, the MMS-2014 contains a certification by the signer that the information contained therein is accurate and complete. Plaintiffs argue the certification is a condition to oil transfer under the Federal Oil and Gas Royalty Management Act of 1982. Defendants respond in turn by relying upon a distinction, supported by citation to dictionaries, between "requisite" and "prerequisite" (#716 at 59-60 & n.34). In other words, a "condition" to transfer is not necessarily a "prerequisite" to transfer. This is a plausible argument, but the word "prerequisite" upon which

defendants so heavily rely, is a gloss on the statute from case law, not a word in the statute itself. In the absence of Tenth Circuit authority, the Court is not persuaded it should partially overturn a jury verdict on such a basis. The verdict as to direct false claims stands¹.

Next, defendants attack plaintiffs' case as a whole, contending that plaintiffs failed to establish a "routine practice" under F.R.Evid. 406 sufficient to permit the jury to find separate FCA violations. In their motion for summary judgment, defendants asked the Court to rule as a matter of law that plaintiffs failed to demonstrate a routine practice. The Court denied the motion, and heard the trial presentation. At the conclusion of trial, the Court made a finding (in accordance with F.R.Evid. 104(a)) that plaintiffs had established a routine practice of adjustments to observed measurements. In the final jury instructions, the jury was told that it was to decide what weight it wished to give to the routine practice which the Court had found. The Court is persuaded that this method complied with the Federal Rules of Evidence and that the evidence supports the finding which the Court made.

Defendants contend that such "routine practice" evidence, even if sufficient for Rule 406 purposes, cannot support the jury's finding that all the elements of an FCA violation were present for each separate violation which the jury found. This is

¹Contrary to plaintiffs' supplemental briefing, the Court does not find the recent decision by the Tenth Circuit in Shaw v. AAA Eng'g & Drafting, Inc., 2000 WL 64029 (10th Cir. May 18, 2000) particularly pertinent on this issue.

unquestionably a powerful argument, and lays bare a core issue in the case. In the vast multi-employee universe of oil measurement, as engaged in by defendants and other companies, a plaintiff could not possibly prove this number of violations over this many years on a lease-by-lease basis. Defendants scoff at this aspect, correctly noting that "'do the best you can' is not a rule of evidence recognized in the federal courts." (#716 at 12 n.3). Again, the Court is persuaded the verdict should stand. In a case of alleged widespread fraud, it does not seem improper that evidence of the so-called "Koch method" should be presented to the jury, so long as a rational method of inference to liability is provided.

In this case, that method of inference was provided by Dr. Howard, plaintiffs' expert witness. Defendants describe Dr. Howard's testimony as "based on demonstrably false assumptions and a shoddy methodology" (#716 at 1). The Court denied defendants' pretrial Daubert motion to exclude Dr. Howard as a witness, and remains persuaded that the testimony was properly presented to the jury, for that body to accept or reject. Under the requisite JMOL standard, the defendants' motion will not be granted on the "routine practice" issue.

Defendants also assert that plaintiffs' evidence was insufficient in general, insufficient as to 100% division order leases, insufficient as to Osage County leases and insufficient as to damages. Under the JMOL standard, the Court is persuaded by the evidence cited in plaintiffs' response briefs that the verdict

should not be disturbed on these grounds either.

Defendants have made certain other arguments, particularly in their first motion (#662) which simply reiterate issues (such as lack of subject matter jurisdiction and application of statutes of limitation) upon which the Court has already ruled and which presumably defendants reiterate for appellate preservation purposes. The Court's previous rulings stand.

Finally, defendants have also raised numerous constitutional challenges to the FCA itself. Plaintiffs argue that these contentions (save lack of Article III standing) were waived by defendants' failure to raise them by motion to dismiss. Supreme Court dicta does provide some support for this argument. "[N]one would suggest that a litigant may never waive the defense that a statute is unconstitutional." Plaut v. Spendthrift Farm, Inc., 514 U.S. 211, 231 (1995). However, in view of the uncertainty of the waiver issue and in the interest of thoroughness, the Court will address the defendants' contentions.

Defendants concede that the recent Supreme Court decision in Vermont Agency of Natural Resources v. United States ex rel. Stevens, 120 S.Ct. 1858 (2000) defeats their argument regarding Article III standing. The Supreme Court stated there is "no room for doubt that a qui tam relator under the FCA has Article III standing." Id. at 1865 (footnote omitted). The Court noted that it was expressing "no view on the question whether qui tam suits violate Article II, in particular the Appointments Clause of § 2 and the "take Care" Clause of § 3." Id. at n. 8.

Defendants have also raised these Article II challenges to the FCA, placing principal reliance upon Riley v. St. Luke's Episcopal Hosp., 196 F.3d 514 (5th Cir.1999), rehearing en banc granted, 196 F.3d 561 (5th Cir.1999). In that decision, a split panel of the Fifth Circuit Court of Appeals held that the qui tam provisions of the FCA violate the Take Care Clause and the separation of powers doctrine. The court found it therefore unnecessary to reach the Appointments Clause issue. 196 F.3d at 531. As already noted, the Fifth Circuit has ordered rehearing of the cause en banc because the panel decision creates "a circuit split." 196 F.3d at 563. Thus, at this time the Riley decision is only a tentative statement of the law of the Fifth Circuit, which is not binding on this Court in any event.

Further, the Riley decision as it stands does indeed create a circuit split, as it opposes decisions by all other circuit courts which have addressed similar challenges. In United States ex rel. Kelly v. Boeing Co., 9 F.3d 743 (9th Cir.1993), cert. denied, 510 U.S. 1140 (1994), the court rejected challenges under separation of powers, the Take Care Clause and the Appointments Clause. See also United States ex rel. Taxpayers Against Fraud v. General Elec. Co., 41 F.3d 1032, 1041 (6th Cir.1994) (same); United States ex rel. Kreindler & Kreindler v. United Tech. Corp., 985 F.2d 1148 (2d Cir.1993) (Take Care Clause and separation of powers challenges). This Court elects to follow the weight of authority and also adopts the cogent discussion in United States ex rel. El Amin v. George Washington Univ., 26 F.Supp.2d 162, 168-170 (D.D.C.1998), which

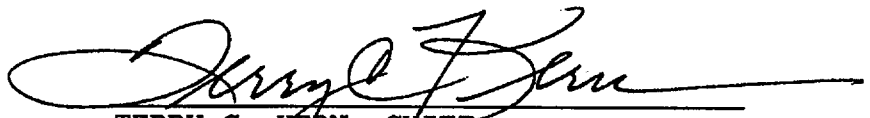
also upheld the constitutionality of the FCA under like challenges.

In view of the foregoing rulings, the Court will also deny plaintiffs' motion for guidance, which inquired about additional briefing and possible oral argument as to the pending motion.

It is the Order of the Court that the motion of the defendants for judgment under Rule 50(a)(2) (#695) is hereby DENIED. The motion of the plaintiffs for guidance (#718) is hereby DENIED.

The parties are asked to confer with their "penalty" witnesses and with each other, and to advise the Court in writing within ten days as to mutually convenient dates for the penalty hearing in this case.

ORDERED this 7 day of July, 2000.


TERRY C. KERN, CHIEF
UNITED STATES DISTRICT JUDGE

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IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF OKLAHOMA

FILED

OCT 29 1998

Phil Lombardi, Clerk
U.S. DISTRICT COURT

UNITED STATES OF AMERICA, *ex rel.*
WILLIAM I. KOCH and WILLIAM A.
PRESLEY,

Plaintiffs,

vs.

Case No. 91-CV-763-K

KOCH INDUSTRIES, INC.;
KOCH EXPLORATION, INC.;
KOCH GATHERING SYSTEMS, INC.;
AND KOCH SERVICE, INC.,

Defendants.

United States District Court)
Northern District of Oklahoma) SS
I hereby certify that the foregoing
is a true copy of the original on file
in this court.

Phil Lombardi, Clerk

By J. Wiederhake
Deputy

**SECOND AMENDED COMPLAINT FOR VIOLATIONS OF THE
FALSE CLAIMS ACT**

WILLIAM I. KOCH and WILLIAM A. PRESLEY, plaintiffs, by their attorneys and on behalf of the United States of America, state the following claims for damages and civil penalties against KOCH INDUSTRIES, INC.; KOCH EXPLORATION CO.; KOCH GATHERING SYSTEMS, INC.; AND KOCH SERVICE, INC. and/or their predecessors or successors (collectively referred to as "Koch").

I. **INTRODUCTION.**

1. This is a *qui tam* action to recover damages and civil penalties on behalf of the United States of America arising from false statements and claims made by Koch against the United States, in violation of the False Claims Act, 31 U.S.C. § 3729 *et seq.* (the "Act" or "FCA").

2. The FCA is designed to enhance the federal government's ability to recover losses sustained as a result of fraud committed against the United States. The Act provides that any

person who knowingly submits a false or fraudulent claim to the United States Government, or who makes, uses, or causes to be made or used a false record or statement to decrease an obligation to pay or transmit money to the federal government, is liable for a civil penalty between \$5,000 and \$10,000 for each such violation, plus three times the amount of the damages sustained by the Government from the violation. 31 U.S.C. § 3729(a).

3. The Act authorizes any person having knowledge of a violation of Section 3729(a) to bring an action for itself and for the United States Government, and to share in any recovery. 31 U.S.C. § 3730(b)(1).

4. Based on these provisions, plaintiffs seek to recover damages and penalties arising from false claims, records, and statements knowingly made to the Government as part of Koch's scheme to decrease the amount of its royalty payments to the United States Minerals Management Service ("MMS") and to its predecessor, the United States Geological Survey ("USGS") for the purchase of crude oil and natural gas from Indian and federal lands. The MMS is the federal agency within the United States Department of the Interior responsible for the accurate and timely determination, collection, and distribution of mineral royalties from Indian and federal lands. The USGS was the federal agency responsible for collecting royalties from Indian and federal lands prior to the establishment of the MMS by the Secretary of the Interior in 1982.

5. As required by 31 U.S.C. § 3730(b)(2), copies of the original complaint and a detailed statement of the material evidence and information available to plaintiffs were provided to the Attorney General of the United States and to the United States Attorney for the Northern District of Oklahoma.

II. PARTIES.

6. Plaintiff William I. Koch, an individual, was formerly a shareholder, director, and employee of defendant Koch Industries, Inc. William I. Koch is a shareholder of The Precision Company ("Precision"), an Oklahoma corporation with its principal place of business in Tulsa, Oklahoma.

7. Plaintiff William Presley, an individual, is a shareholder of Precision.

8. Koch Industries, Inc., is a Kansas corporation with its principal place of business in Wichita, Kansas. Upon information and belief, Koch is a closely-held, privately-owned corporation, having annual sales in excess of twenty-five billion dollars (\$30,000,000,000). Koch is the largest independent purchaser of crude oil in the United States and Canada, as well as the single largest purchaser of Indian oil and gas reserves.

9. Koch Exploration Company is a Kansas corporation with its principal place of business in Wichita, Kansas.

10. Koch Service, Inc., is a Kansas corporation with its principal place of business in Wichita, Kansas.

11. Koch Gathering Systems, Inc., is a Montana corporation, with its principal place of business in Wichita, Kansas.

III. JURISDICTION AND VENUE.

12. This Court has subject matter jurisdiction over this action pursuant to 28 U.S.C. § 1331 and 31 U.S.C. § 3732(a), which specifically confers jurisdiction on this Court for False Claims Act actions. In further support of this allegation, plaintiffs adopt the facts alleged in Part IV(A) below.

13. This Court has personal jurisdiction over Koch because Koch submitted, and caused others to submit, false claims to the United States Government, and made, used, and caused to be made or used false records or statements to decrease an obligation to pay or transmit money to the federal government, with respect to its operations in obtaining crude oil and natural gas from Indian and federal leases located throughout the United States. Defendants can be found in, are authorized to transact business in, and are transacting business in this District.

14. Venue is proper in this District pursuant to 28 U.S.C. § 1391 and 31 U.S.C. § 3732(a).

IV. BACKGROUND FACTS.

A. Plaintiffs' Investigation.

15. The present lawsuit is based upon information obtained through plaintiffs' extensive, independent investigation of defendants' crude oil and gas measurement practices. The investigation was commenced in or about October 1987 by plaintiff William I. Koch, a former director, officer, and shareholder of Koch Industries, in connection with a lawsuit that he and other Koch shareholders had filed against the company. As a result of an extensive investigation, William I. Koch discovered that defendants, through a management-driven scheme, were systematically cheating the United States Government, certain Indian tribes, and other parties of millions of dollars in oil and gas royalties.

16. Plaintiff William Presley was closely involved in William I. Koch's investigation from the beginning. In January 1988 William I. Koch retained Mr. Presley to interview and retain oil field experts, investigators, former Koch gaugers, and potential witnesses to gather evidence of defendants' fraudulent measurement practices. Between February and June 1988, Mr.

Presley worked with William I. Koch investigating and substantiating the factual allegations underlying this lawsuit. As a part of this investigation, Mr. Presley interviewed numerous former Koch employees and retained oil and gas measurement experts. In addition, plaintiffs gathered physical and documentary evidence of defendants' oil theft, recalibrated or "backstrapped" oil storage tanks from which defendants purchased crude oil, and analyzed thousands of pages of documents. In June 1989 Mr. Koch and Mr. Presley formed Precision for the specific purpose of investigating instances of mismeasurement by oil companies and recovering monies due producers and royalty owners.

17. In approximately July 1988 federal agents assigned to an unrelated Senate subcommittee investigation into fraud, corruption, and mismanagement of Indian affairs approached William I. Koch to debrief him on the results of his independent investigation. Plaintiffs voluntarily cooperated with the agents and, in October 1988, gave them complete access to their information, documents, and work product confirming oil and gas theft by Koch. Between October 1988 and May 1989 plaintiffs continued to provide the agents with additional information and evidence as it was uncovered through their continuing independent investigation. The Senate investigators relied heavily on plaintiffs' information and assistance in conducting their own investigation into defendants' affairs.

18. In May 1989 the Special Committee on Investigations of the United States Senate's Select Committee on Indian Affairs ("Special Committee") held public hearings on the subject of fraud, corruption, and mismanagement in American Indian affairs. A full day, May 9th, was devoted to testimony on the issue of crude oil thefts from Indian lands. Several former Koch oil field workers testified that defendants had systematically stolen crude oil from Indian lands; prior

to testifying before the Special Committee, many of these individuals had *previously* given statements to plaintiffs during plaintiffs' investigation. Defendants later accused William I. Koch of "sparking" the Senate investigation into their oil measurement practices:

The fact that the May 9th hearing was devoted almost exclusively to Koch Industries is a *direct result* of the efforts of William I. Koch [Precision's principal shareholder]. Having limited resources, the staff obviously embraced the allegations of William I. Koch. They used his witnesses and relied on the statements his investigators delivered to them. . . .

(Koch's June 8, 1989 Statement to United States Senate, p. 3 (emphasis added).) In November 1989, the Special Committee issued a formal report in which it concluded that the evidence against defendants was "overwhelming," and described defendants practices as "sophisticated oil theft" and "management-directed oil theft." The Subcommittee's report concluded:

Koch Oil . . . a subsidiary of Koch Industries and the largest purchaser of Indian oil in the country, *is the most dramatic example of an oil company stealing by deliberate mismeasurement and fraudulent reporting.*

(Special Comm. on Investigations, Senate Comm. on Indian Affairs, 101st Cong. 1st Sess., pt. 60, at 105 ("Senate Report") (emphasis added).)

B. Procedural History.

19. On May 25, 1989, Precision filed under seal in this Court its original complaint against the defendants in accordance with the *qui tam* provisions of the False Claims Act. *United States of America ex rel. the Precision Company v. Koch Industries, Inc., et al.*, No. 89-C-437-C ("*Precision I*"). As required by the Act, Precision provided a copy of the complaint in *Precision I* and a confidential memorandum providing evidentiary support for Precision's claims to the United States Department of Justice ("DOJ"). After *Precision I* was filed, plaintiffs continued their investigation and gathered additional information, including statements of witnesses familiar

with Koch's fraudulent measurement practices, all of which was subsequently provided to the Government.

20. On June 8, 1989, Koch submitted a statement to the Special Committee. In its statement, Koch claimed William I. Koch was the source and driving force behind the Senate investigation, averring that the fact that the May 9th hearing was devoted almost exclusively to Koch Industries was a direct result of the efforts of William I. Koch.

21. In November 1989, the Senate Report concluded, *inter alia*, that Koch was "the most dramatic example of an oil company stealing by deliberate mismeasurement and fraudulent reporting. Although Koch is also the largest independent purchaser of crude oil in the United States and Canada and the largest in Oklahoma, the company pilfered additional oil from American Indians and others." (Senate Report at 105-106.)

22. On January 23, 1990, after evaluating the independent investigation, the Government declined to intervene formally in *Precision I*. The Government did not object to Precision's continuing the action, and specifically reserved the right to intervene at a later time. On March 5, 1990, the complaint was removed from under seal and served on Koch.

23. On April 16, 1990, the defendants filed a Motion to Dismiss in *Precision I* alleging that the district court lacked subject matter jurisdiction over Precision's *qui tam* claims. Specifically, defendants argued that Precision's claims were "based upon" publicly disclosed information and that Precision had failed to show that it was an "original source" of that information. Defendants maintained that absent such a showing, the action was jurisdictionally barred under 31 U.S.C. §§ 3730(e)(4)(A) and (B).

24. On November 27, 1990, the district court granted defendants' Motion to Dismiss in *Precision I*, ruling that Precision's complaint was based, at least in part, upon publicly disclosed information. The district court held that, as a matter of law, a *qui tam* action based "in any degree" upon public disclosures required the court to proceed to an "original source" analysis under § 3730(e)(4)(B). Turning to the latter issue, the district court held that, in order to qualify as an "original source," a plaintiff must have provided the Government with "all" information in its possession upon which the civil action is based. Finding that certain information relied upon by Precision had not been turned over to the Government, the district court held that Precision did not qualify as an "original source" under the statute.

25. On September 30, 1991, while their appeal of the district court's ruling was pending before the United States Court of Appeals for the Tenth Circuit, plaintiffs filed their complaint in the present action ("*Precision II*"), containing allegations identical in all material respects to those in *Precision I*. The *Precision II* complaint included affidavits showing that prior to the filing of the new action, plaintiffs had turned over all of the information in their possession to the Government, thus curing the alleged jurisdictional defect that caused the district court to dismiss the complaint in *Precision I*. The district court issued a stay in *Precision II* pending the outcome of the *Precision I* appeal in the Tenth Circuit.

26. On July 27, 1992, the Tenth Circuit affirmed the district court's dismissal on different grounds, holding that the *Precision I* complaint was based primarily upon information gathered by William I. Koch and William Presley prior to the incorporation of Precision in June 1988. The Tenth Circuit held that Precision had "made no showing" that it had a legitimate claim to the information gathered by Mr. Koch and Mr. Presley, its only shareholders, and that Precision's

information was a continuation of, or derived from, Mr. Presley's and Mr. Koch's individual investigations. The Tenth Circuit thus concluded that Precision was not an "original source," and on that ground affirmed the district court's dismissal of the complaint in *Precision I*.

27. On August 3, 1992, following the ruling of the Tenth Circuit in *Precision I*, plaintiffs filed their amended complaint in the present action. The amended complaint added William I. Koch and William Presley as individual plaintiffs, but in all other respects was identical to the *Precision I* complaint and the original *Precision II* complaint. Defendants moved to dismiss the amended complaint on the grounds that the addition of Mr. Koch and Mr. Presley was precluded by 31 U.S.C. § 3730(b) (barring intervention by private citizens in an FCA case), and by Fed. R. Civ. P. 21, which provides that parties may only be added with "leave of court." The district court granted the motion and plaintiffs appealed.

28. The Tenth Circuit reversed the district court, holding that plaintiffs were entitled to amend their complaint as a matter of right, pursuant to Fed. R. Civ. P. 15(a), because the amendment was made prior to the filing of a responsive pleading by defendants. *United States ex rel. Precision Co. v. Koch Industries, Inc.*, 31 F.3d 1015 (10th Cir. 1994).

29. Following remand of the case to district court, Precision was voluntarily dismissed, leaving only Mr. Koch and Mr. Presley as plaintiffs. Defendants filed yet another motion to dismiss, pursuant to Fed. R. Civ. P. 12(b)(1), contending that plaintiffs lacked "direct and independent knowledge" of the facts upon which the allegations in the complaint were based. Alternatively, defendants moved, pursuant to Fed. R. Civ. P. 12(b)(6), to dismiss portions of the amended complaint relating to (1) false claims submitted to the Government prior to October 27, 1986, and (2) the theft of crude oil and gas from Indian lands. On October 6, 1995, the district court

denied defendants' 12(b)(1) motion. The district court also denied defendants' 12(b)(6) motion, except that portion pertaining to the theft of oil and gas from Indian lands prior to October 27, 1986.

30. Defendants petitioned the Tenth Circuit for leave to appeal the district court's ruling. On October 30, 1996, the Tenth Circuit summarily denied defendants' petition.

C. Koch's Operations.

31. Koch is engaged in, among other things, the exploration, production, purchasing, refining, and transportation of crude oil throughout the United States. In connection with these activities, Koch owns and operates approximately 37,000 miles of pipelines extending throughout various states, including Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Nebraska, North Dakota, Oklahoma, and Texas. Koch purchases a substantial amount of crude oil from Indian lands managed by the Bureau of Indian Affairs ("BIA") and federal lands managed by the Bureau of Land Management ("BLM"). Upon information and belief, Koch purchases, and has purchased, a substantial number of barrels of crude oil per year from more than 2,000 crude oil-producing leases located on Indian and federal lands in various states, including California, Colorado, Kansas, Montana, New Mexico, North Dakota, Oklahoma, South Dakota, Utah, and Wyoming.

32. Koch also is engaged in the exploration, processing, purchasing, and transportation of natural gas throughout the United States. At all times relevant to this case, Koch owned and operated eight natural gas liquids extraction plants and 3,900 miles of natural gas pipelines in Colorado, Kansas, Louisiana, Mississippi, Montana, North Dakota, Texas, and Utah, as well as a natural gas liquids fractionator located in Oklahoma.

33. Koch purchases a substantial amount of natural gas from Indian and federal lands. Upon information and belief, Koch purchases, and has purchased, a substantial volume of natural gas from more than 200 natural gas producing leases located on federal lands in various states, including Colorado, Montana, North Dakota, and Utah.

C. The Federal Payment Process for Oil and Gas.

34. The purchase of crude oil or natural gas from Indian and federal lands is a multi-faceted process. Several distinct entities can be involved in the leasing, production, operation, and purchase of crude oil or natural gas from Indian and federal lands. One of the entities, the lessee, generally enters into a lease agreement with either the BIA or BLM, entitling the lessee or its assignee to remove crude oil or natural gas from the land.

35. Payment to the MMS is made by either the producer or purchaser of the crude oil or natural gas, and the payor is designated on the MMS Payor Information Form. Royalty payments are based on both the volume and the gravity (quality) of crude oil or natural gas extracted from the land. Federal regulations require that the royalty and the amount of crude oil or natural gas extracted from each federal or Indian lease be reported monthly by the royalty payor to the MMS.

36. Koch is the party responsible for making royalty payments on thousands of leases and, even when not directly responsible for making the royalty payment, Koch is responsible for providing the information used by other royalty payors to determine their royalty obligations to the federal government.

37. Koch has been involved in all aspects of the business of obtaining crude oil and natural gas from Indian and federal lands. From time to time, Koch has operated both as the

lessee and the purchaser of the crude oil or natural gas. In some cases, Koch has designated itself, or has been designated, as the royalty payor and has submitted royalty payments to the MMS. In other cases, Koch has been the purchaser of crude oil or natural gas, or has been involved only in the operation of the crude oil or natural gas facilities, and has not been the entity designated to make royalty payments to the MMS. However, even in the latter cases, the royalty payor has relied upon Koch's measurement processes and documentation in determining the royalty due the federal government.

38. The royalty payments made by Koch and other entities to the MMS represent a percentage, between 12.5% and 20%, of the total value of the measured crude oil or natural gas removed from a lease. Pursuant to federal regulations, the royalty payments must be based upon the gross proceeds accruing, or that could accrue, to the lessee from an arms-length sale of the crude oil or natural gas removed from a lease.

39. Koch made royalty payments on more than 150,000 separate purchases for crude oil and natural gas to the USGS and the MMS between 1979 and December 1996. In addition to making fraudulent royalty payments, Koch has furnished false information to other entities that have been responsible for making monthly royalty payments to the United States Government.

D. The Government Relies on Koch.

40. The United States Government, as owner of the crude oil and natural gas sold, relies upon Koch to measure accurately and account for the volume and quality/ gravity of crude oil and/or natural gas purchased. The nature of this business and the process by which crude oil and natural gas are purchased creates an opportunity for Koch to take unfair advantage of the United States Government.

41. Koch purchases crude oil at the lease site after it has been pumped from oil wells. The oil is typically pumped into a storage tank near the well, and when the tank is full, the producer calls Koch to have a "gauger" visit the site to measure the volume and quality/ gravity of oil in the tank. In other cases the oil is metered at the lease. Once the oil is measured, Koch transports it by truck or pipeline to one of its gathering stations. When the tank at the lease is emptied by Koch, and trucked or pipelined away, more oil begins to flow into the tank, covering up any evidence of mismeasurement.

42. When Koch buys crude oil from a tank for the first time, it prepares a volume chart that is used for all future measurements. Koch prepares the volume chart from data taken by Koch personnel in measuring the tank's circumference at various heights above the tank's foundation -- a process called "strapping."

43. The producer or operator of the oil well, as well as the royalty owners, rely on the gauger to measure accurately the amount and quality of crude oil being taken from the storage tank. The gauger takes several different measurements. First, the gauger measures the height of the oil in the tank before it is pumped -- a measurement known as the "top gauge." Next, the gauger records the crude oil's temperature and takes a sample of the oil to determine its gravity and the amount of basic sediment and water ("BS&W") contained in the crude oil. The height, temperature, and BS&W measurements are used to determine the actual volume of oil in the tank, and the gravity measurement effects the price per barrel of the oil. After the tank is pumped, the gauger measures the bottom gauge (the height of the remaining oil) and its temperature. Following these measurements, Koch's gauger completes a run ticket containing in some cases observed measurements and in the majority of cases altered measurements indicating a volume and

quality/gravity of oil and sends the information to Koch's headquarters in Wichita. Koch's payment to the producer and royalty owners is based upon the volumetric and gravity measurements recorded by the gauger on the run ticket, as well as the volume chart for the particular tank. All of this data is fed into a computer by Koch's crude oil accounting department in Wichita to determine the actual amounts paid to the producer and royalty owners.

44. Koch obtains natural gas from federal lands by extracting it from the land through wells or by purchasing it from other operators. The natural gas is measured by meters installed, owned, and operated by Koch. The volume of gas taken is computed by meters which record the flow of gas over a continuous period onto a circular paper chart with an ink pen. The information on this chart is placed into a computer which calculates the volume of gas flowing through the meter. This computation process is called "integration." The integration process takes into account a number of variables that affect calculation of gas volume, such as pressure base, temperature base, and specific gravity. Again, the gas producer depends on Koch to measure accurately the amount of gas being purchased, and royalty owners, including the Government, depend on Koch to measure accurately the amount of gas to receive proper royalty payments.

E. Koch's Fraudulent Acts.

45. Koch has used its gaugers to engage in a systematic pattern of defrauding royalty owners and producers of crude oil, including the United States Government. That fraudulent scheme and plan includes, but is not limited to, the following acts:

- a. Falsifying, in Koch's favor, a tank's top gauge by recording on the run ticket an oil height less than is actually observed in the tank before pumping;
- b. Falsifying, in Koch's favor, a tank's bottom gauge by recording on the

run ticket an oil height greater than is actually observed in the tank after pumping;

c. Falsifying, in Koch's favor, the temperature of the oil in a tank by recording on the run ticket a top gauge oil temperature greater than the observed oil temperature and/or recording on the run ticket a bottom gauge oil temperature less than the observed oil temperature, thereby understating on the run ticket the actual volume of oil taken by Koch;

d. Falsifying, in Koch's favor, the BS&W content of the oil by inflating the observed BS&W, or adding foreign matter to the test sample to falsely increase the BS&W, thereby understating on the run ticket the actual volume of oil taken by Koch;

e. Falsifying, in Koch's favor, the circumferences of a tank when strapping the tank, thereby ensuring that Koch receives more crude oil than it pays for each time it purchases from that tank; and

f. Falsifying, in Koch's favor, the API gravity or hydrometer temperature of the crude oil on the run ticket, thereby allowing Koch to purchase the oil at a price below its true market value.

46. Crude oil is also pumped from oil wells or storage tanks directly into Koch's gathering pipelines. Crude oil collected in this manner is measured by gaugers and by meters. Koch has engaged in a practice of miscalibrating the meters by misstating the oil temperature and the "meter counts" during the meter-proving process, all with the purpose and effect of allowing Koch to receive oil without paying for it.

47. Koch has taught its gaugers methods for understating crude oil purchases, using phrases such as "don't come in short," "get home with the barrel," and "work your oil" to impress upon gaugers the need to achieve crude oil overages.

48. Koch's fraudulent activities have been known, authorized, taught, supported, and rewarded by the highest levels of Koch management. Indeed, Koch upper management even budgeted in advance for anticipated revenue from volume mismeasurement and gravity fraud.

49. Since at least 1979 through the present, Koch, through the illegal acts described below, has knowingly made, used, or caused to be made or used false records or statements, submitted false claims, and caused others to submit false claims to the United States Government, thereby unlawfully decreasing its obligation to pay the proper amount for the crude oil and natural gas it obtains from Indian and federal lands.

COUNT I
(FALSE CLAIMS WITH RESPECT TO PURCHASES OF CRUDE OIL)

50. Plaintiffs reallege and incorporate herein each and every allegation set forth in paragraphs 1-49, inclusive, as though fully set forth herein.

51. Koch has violated 31 U.S.C. § 3729(a)(7) and other provisions of the False Claims Act by knowingly making, using, and causing to be made or used, false records and statements to conceal and decrease the obligation of Koch and other entities to pay money to the United States Government in exchange for crude oil. Koch made, and caused to be made, these false records and statements by several different means, including, but not limited to, the following:

- a. Falsely recording, in Koch's favor, the height or top gauge of crude oil in an owner's tank before it is emptied;
- b. Falsely recording, in Koch's favor, the temperature of the crude oil in an owner's tank before and after it is emptied;
- c. Falsely recording, in Koch's favor, the BS&W content of the crude oil,

thereby understating, in Koch's favor, the volume of oil purchased;

d. Falsely recording, in Koch's favor, the height or bottom gauge of the crude oil in an owner's tank after it is emptied;

e. Falsely recording the circumference of an owner's tank, on the strapping report, thereby understating the volume of crude oil in that tank at any given height; and

f. Falsely recording, in Koch's favor, the observed API gravity and hydrometer temperature of the crude oil when purchased, thereby allowing Koch to purchase the oil at a price below its fair market value.

52. Additionally, in cases where Koch purchases crude oil using meters, Koch knowingly has acquired crude oil without paying for it by recording a false meter correction factor through the use of false temperatures or meter counts when proving the meter.

53. Koch has made false claims in an amount not yet determined, but which exceeds 150,000 claims for crude oil and natural gas.

54. According to MMS records, from 1979 through 1996 Koch purchased in excess of \$340,000,000 in crude oil from Government and Indian leases for which it paid royalties. This sum does not include crude oil purchases for which other entities paid royalties to the federal government in reliance on measurements by Koch gaugers. As a direct result of Koch's false statements and false claims, the amount of crude oil unlawfully taken between 1979 and December 1996, from Indian and federal lands, conservatively exceeds \$1,000,000, before trebling, plus interest.

COUNT II
(FALSE CLAIMS WITH RESPECT TO PURCHASES OF NATURAL GAS)

55. Plaintiffs reallege and incorporate herein each and every allegation set forth in paragraphs 1-49, as though fully set forth herein.

56. Koch has violated 31 U.S.C. § 3729(a)(7) and other provisions of the FCA by knowingly making, using, and causing to be made or used, false records and statements to conceal and decrease the obligation of Koch and other entities to pay money to the United States Government in exchange for natural gas. Koch has accomplished this by several different means, including, but not limited to,

a. Disguising a non-allowable 2¢/gallon marketing fee or margin as an allowable fractionation fee, thereby, on information and belief, causing third parties to understate the net sales proceeds from gas plant products for royalty payment purposes; and

b. Deducting \$1.65 per barrel from the price paid for natural gasoline, thereby fraudulently understating the net sales proceeds from natural gasoline for royalty payment purposes; and

57. Koch has made false claims in an amount not yet determined, but which exceeds 150,000 claims for crude oil and natural gas.

58. According to MMS records, between 1979 and 1996 Koch purchased in excess of \$1,000,000,000 in natural gas from Government and Indian leases for which it paid royalties. This sum does not include natural gas purchases for which other entities paid royalties to the federal government in reliance on measurements by Koch gaugers. As a direct result of Koch's false statements and false claims, Koch underpaid or caused others to underpay royalties on natural

gas produced from Indian and federal lands, in an amount to be proven at trial.

WHEREFORE, William I. Koch and William A. Presley, on behalf of the United States Government, respectfully pray for judgment against Koch as follows:

1. That this Court enter judgment finding that Koch violated the False Claims Act, 31 U.S.C. § 3729, *et seq.*, by making, using, and causing to be made or used false records or statements to decrease an obligation to pay or transmit royalties to the federal government for crude oil and natural gas removed from Indian and federal land;

2. That Koch be ordered to cease and desist from further violating 31 U.S.C. § 3729;

3. That this Court award to the United States Government three times the total amount of damages the United States Government sustained as a result of Koch's violations of the False Claims Act, plus a civil penalty of \$10,000 for each separate violation of the False Claims Act committed by Koch on or after October 27, 1986, and a civil penalty of \$2,000 for each violation committed prior to October 27, 1986;

4. That this Court award William I. Koch and William A. Presley thirty percent (30%) of the total damages and penalties awarded to the United States Government, plus the attorneys' fees and court costs incurred in prosecuting this action on behalf of the United States Government; and

5. That this Court award plaintiffs such other and further relief as this Court deems just and equitable.

PLAINTIFFS HEREBY DEMAND TRIAL BY JURY.

Respectfully submitted,

James M. Sturdivant, OBA #8723
David E. Keglovits, OBA #14259
GABLE & GOTWALS
2000 NationsBank Center
15 West Sixth Street
Tulsa, Oklahoma 74119-5447
(918) 582-9201

and

Roy Morrow Bell
Timothy P. Irving
MILLER, BOYKO AND BELL
550 West B Street, Suite 400
San Diego, California 92101-3599
(619) 235-4040

BY: 

David E. Keglovits

Attorneys for Plaintiffs

CERTIFICATE OF MAILING

I hereby certify that on the 29th day of October, 1998, a true and correct copy of the above and foregoing instrument was served as noted:

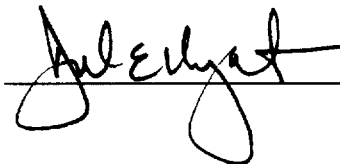
Robert L. Howard, Esq. (via overnight mail and facsimile)
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Clyde A. Muchmore, Esq. (via overnight mail and facsimile)
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Assistant United States Attorney
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David Luce, Esq. (via overnight mail and facsimile)
Legal Department -- Litigation Section
Koch Industries, Inc.
4111 E. 37th St. North
Wichita, KS 67220

A handwritten signature in black ink, appearing to read "David Luce", is written over a horizontal line.

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United States District Court
Northern District of Oklahoma
I hereby certify that the foregoing
is a true copy of the original on file
in this court.

Phil Lombardi, Clerk

By J. Wiederholt
Deputy

IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF OKLAHOMA

FILED

OCT 25 2000

Phil Lombardi, Clerk
U.S. DISTRICT COURT

UNITED STATES OF AMERICA, *ex rel.*)
WILLIAM I. KOCH and WILLIAM A.)
PRESLEY,)
)
Plaintiffs,)
)
vs.)
)
KOCH INDUSTRIES, INC., *et al.*,)
)
Defendants.)

Case No. 91-C-763-K(J)

JOINT APPLICATION TO STRIKE THE PENALTY PHASE PROCEEDING

The relators and the defendants respectfully request that the Court strike the penalty phase proceeding currently scheduled for October 30, 2000. In support of this joint application the relators and defendants would show as follows:

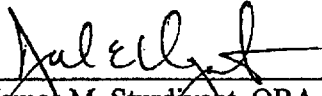
- (1) the relators and the defendants have been engaged in settlement discussions over the last few months;
- (2) the relators and the defendants have reached an agreement that would settle all matters pending before the Court, but require time to inform the government of the agreement and to ascertain the government's position on it;
- (3) the relators and the defendants fully anticipate that the government will join in the proposed agreement and that the parties will be in a position to dismiss this matter with prejudice in the near future;
- (4) counsel for relators has been authorized to sign this application on behalf of defendants so as to bring this matter to the Court as quickly as possible.

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DIB 015

Accordingly, the relators and the defendants jointly apply to the Court for an order striking the penalty phase hearing and an order setting a status conference at the Court's earliest convenience but not earlier than December 1, 2000.

Respectfully submitted,



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David E. Keglövits, OBA #14259
GABLE & GOTWALS, INC.
1100 ONEOK Plaza
Tulsa, Oklahoma 74103
(918) 595-4800

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San Diego, California 92101-3599
(619) 235-4040

ATTORNEYS FOR PLAINTIFFS

CERTIFICATE OF MAILING

I hereby certify that on the 25th day of October, 2000, a true and correct copy of the above and foregoing instrument was faxed and sent by Federal Express, to:

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Washington, D.C. 20005

and by United States Mail with proper postage thereon to:

Steve Altman
Gordon Jones
United States Department of Justice
Civil Division, Commercial Litigation Branch
Post Office Box 261
Ben Franklin Station
Washington, D.C. 20044

Phil Pinnell
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333 W. 4th Street
Tulsa, Oklahoma 74103-3809



DAVID E. KEGLOVITS

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IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF OKLAHOMA

FILED
MAY 22 2001

UNITED STATES OF AMERICA, *ex rel.*
WILLIAM I. KOCH and WILLIAM A.
PRESLEY,

Plaintiffs,

v.

KOCH INDUSTRIES, INC., *et al.*,

Defendants.

Phil Lombardi, Clerk
U.S. DISTRICT COURT

CIVIL ACTION NO. 91cv763-K(J)✓

ENTERED ON DOCKET

DATE 5-23-01

ORDER

WHEREAS on May 22, 2001, Relators William I. Koch and William A. Presley and Defendants Koch Industries, Inc., et al. (collectively "Koch"), pursuant to Federal Rule of Civil Procedure 41(a)(1), submitted to the Court a stipulation of dismissal. Having considered the stipulation, the arguments or counsel and good cause appearing therefore, the Court hereby ORDERS as follows:

1. All claims in this action are dismissed with prejudice to the Relators and the United States.

2. Because the jury verdict has not been entered, it has no binding or preclusive effect on any party or court. Accordingly, the Relators' and Koch's request that the jury verdict be vacated is denied as moot.

IT IS SO ORDERED.

Dated: May 22 2001

United States District Court)
Northern District of Oklahoma) SS

I hereby certify that the foregoing
is a true copy of the original on file
in this court.

Phil Lombardi, Clerk

By J. Wiederholt
Deputy


The Honorable Jerry Kern
United States District Judge

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

P.D. HAMILTON, Individually and as	§	
Trustee of the Prentice Dell Hamilton and	§	
Florine Hamilton Family Trust	§	
	§	
VS.	§	CIVIL ACTION NO. 9:01CV132
	§	
KOCH INDUSTRIES, INC., Individually	§	
and d/b/a KOCH HYDROCARBON	§	
COMPANY, KOCH PIPELINE	§	
COMPANY, L.P., KOCH PIPELINE	§	
COMPANY, L.L.C., GULF SOUTH	§	
PIPELINE COMPANY, L.P.,	§	
GS PIPELINE COMPANY, L.L.C.,	§	
ENTERGY-KOCH, L.P., and	§	
EKLP, L.L.C.	§	

APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS

VOLUME 5 OF 5

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF TEXAS
LUFKIN DIVISION

**P.D. HAMILTON, Individually and as
Trustee of the Prentice Dell Hamilton and
Florine Hamilton Family Trust**

VS.

CIVIL ACTION NO. 9:01CV132

**KOCH INDUSTRIES, INC., Individually
and d/b/a KOCH HYDROCARBON
COMPANY, KOCH PIPELINE
COMPANY, L.P., KOCH PIPELINE
COMPANY, L.L.C., GULF SOUTH
PIPELINE COMPANY, L.P.,
GS PIPELINE COMPANY, L.L.C.,
ENTERGY-KOCH, L.P., and
EKLP, L.L.C.**

**APPENDIX TO
PLAINTIFF P.D. HAMILTON'S RESPONSE TO
THE KOCH DEFENDANTS' MOTION TO DISMISS**

VOLUME 5 OF 5

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**RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DOCKET NO. 8869**

ENFORCEMENT ACTION AGAINST KOCH PIPELINE COMPANY, L.P. AND KOCH REFINING COMPANY, L.P. FOR VIOLATIONS OF PIPELINE SAFETY REGULATIONS AT THE HAZARDOUS LIQUID SYSTEMS/CORPUS, AT KOCH PL/CORPUS CHRISTI, AT KOCH PL/MEDFORD, AND AT KOCH REF. LP/CORPUS CHRISTI.

COMPROMISE SETTLEMENT AGREEMENT AND FINAL ORDER

On this the 5~~th~~ day of MAY 1998, the above-entitled and numbered docket came on for consideration by the Railroad Commission of Texas ("Commission"). The staff of the Commission's Enforcement Section, through its attorney, announced that the staff, and Koch Industries, Inc., Koch Gateway Pipeline Company, Koch Hydrocarbon Company, Koch Pipeline Company, L.P., and Koch Refining Company, L.P. (collectively referred to herein as "Koch"), have agreed on an informal disposition of the matters involved in this docket by this Compromise Settlement Agreement And Final Order ("Agreement"), subject to the approval of the Commission.

In settlement of this docket, the parties have agreed and stipulated as follows:

1. The Pipeline Safety Section of the Commission's Gas Services Division has conducted a review of the pipeline systems and units within the State of Texas of Koch Gateway Pipeline Company, Koch Hydrocarbon Company, Koch Refining Company, L.P., and Koch Pipeline Company, L.P., with the cooperation of Koch ("Review").
2. The Review covered 6,836 miles of pipeline which includes the interstate system, the intrastate system and non-regulated systems. The interstate system was inspected under temporary authority from the Department of Transportation which expired at the end of calendar year 1997. Approximately 30% of this system was inspected before expiration of the temporary authority. The Pipeline Safety Section of the Commission's Gas Services Division understands that the Department of Transportation will be continuing the inspection of this system in 1998. The intrastate system which is directly under the safety jurisdiction of the Commission covers about 31% of the mileage inspected. The interstate system which is directly under the jurisdiction of the Department of Transportation comprise about 33% of the systems. The remaining 36% comprise the systems that are not directly covered by the Department of Transportation's or the Commission's safety jurisdiction due to rural gathering line exemptions.
3. Such Review has identified alleged pipeline safety violations.
4. Koch is the owner and/or operator of the Hazardous Liquid System/Corpus, the Koch PL/Corpus Christi, the Koch PL/Medford, and the Koch Ref. LP/Corpus Christi units.

Compromise Settlement Agreement and Final Order, GUD No. 8869, Page 2

5. Koch makes no admission of any alleged pipeline safety violations, but wishes to address the Commission's concerns under the terms of this Agreement.
6. The Commission and Koch wish to further the goal of safe operation of pipeline facilities within the State of Texas.
7. The Commission has determined that the facts of this case warrant an informal disposition of the Commission's concerns under the terms of this Agreement.
8. An opportunity for hearing regarding the above-entitled and numbered docket was given to Koch, and Koch, as the owner and/or operator of the Hazardous Liquid System/Corpus, the Koch PL/Corpus Christi, the Koch PL/Medford, and the Koch Ref. LP/Corpus Christi units, has elected not to avail itself of the opportunity for public hearing.
9. The following corrective actions are targeted to improve safety on the entire Texas operations, not just the 31% under direct Commission regulatory control. Koch agrees to comply with the terms and time guidelines for evaluating the existing risk assessment plans being utilized in the operations of their natural gas, crude oil, and products pipeline systems in the State of Texas, as set out in the following three phases:

PHASE 1

Koch will present their risk assessment programs to the Commission's Pipeline Safety staff, at the Commission's Austin office. The programs will be presented by Koch representatives and will detail the current risk assessment tools utilized in the operations of their pipeline facilities in the State of Texas. The presentation will include background information on the programs, including system identification methods, risk factor determination and management tools for the associated risks. Such presentation will take place during the period June 15 - 19, 1998. This meeting is to present the programs currently in effect. Discussion of the programs' elements will continue in Phase 2.

PHASE 2

Koch and the Pipeline Safety staff will meet to discuss the risk management programs for consideration of recommendations and possible alterations to the plans to address the concerns raised in the recent safety and program review. Both parties will exchange information relevant to the plans' contents to determine the need for revisions or suggestions for a more effective programs. This meeting will take place during the period August 17 - 21, 1998. This meeting will develop proposed changes from Commission and Koch to the risk assessment programs for inclusion in risk management plans for Koch Gateway Pipeline Company, Koch Hydrocarbon Company, Koch Refining Company, L.P., and Koch Pipeline Company, L.P. The adoption of any mutually agreed upon suggestions will be incorporated into Phase 3.

Compromise Settlement Agreement and Final Order, GUD No. 8869, Page 3

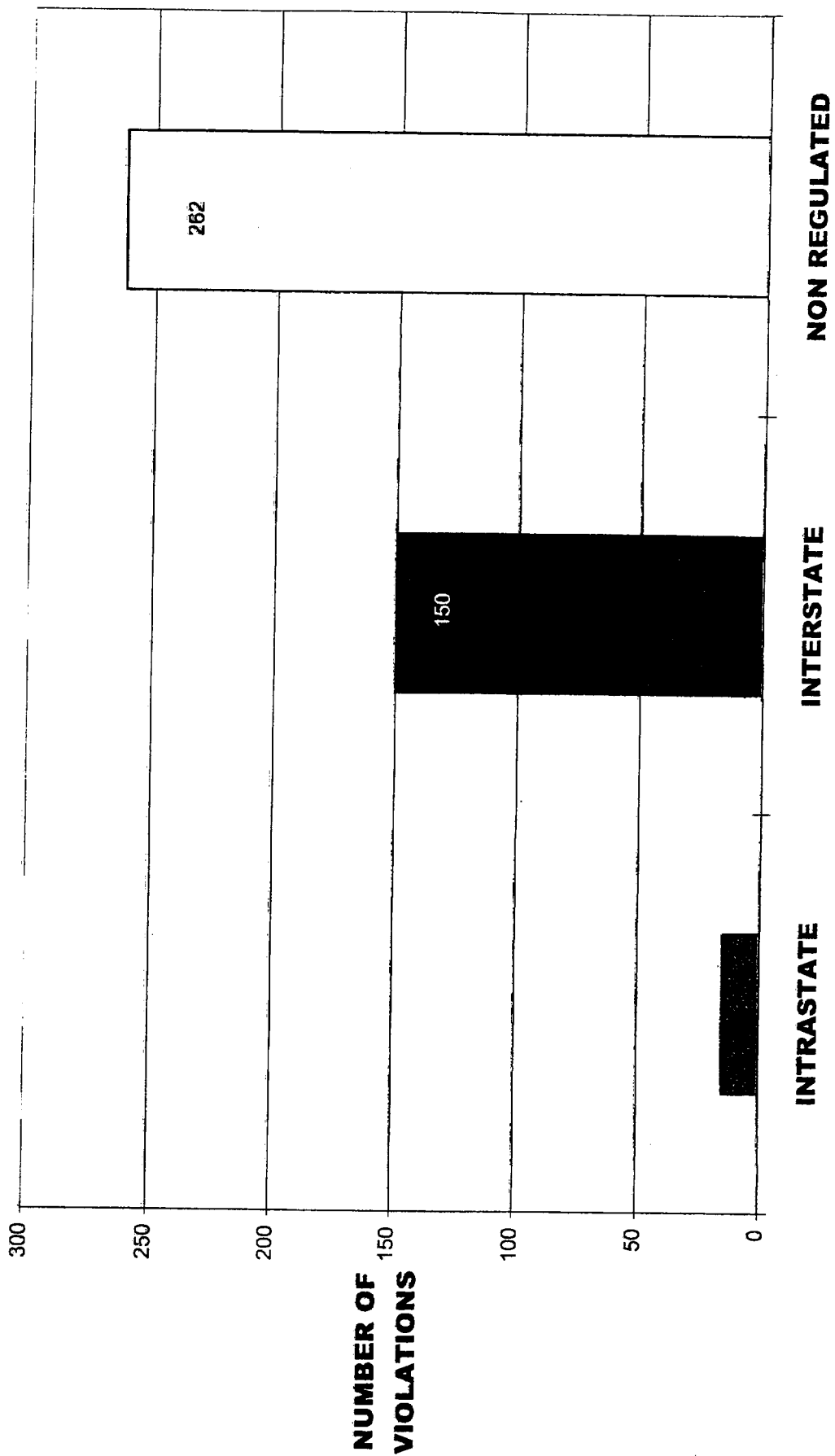
PHASE 3

This phase will focus on the proposed implementation of the risk assessment/management programs discussed in the prior phases. A meeting will be held during the period October 5 - 9, 1998, which will set any mutually agreed guidelines and timelines for implementation and for future evaluation of program goals as well as development of any mutually agreed performance measures to determine compliance.

The time periods for presentations and meetings established by this item may be modified only by mutual written consent of Koch and the Pipeline Safety Section of the Commission's Gas Services Division.

10. In addition to any other reporting requirement under law, Koch agrees to provide prompt notice to the Pipeline Safety Section of the Gas Services Division of any sale, transfer, or other change in ownership of those pipeline systems which it owned or operated within the State of Texas, as of the effective date of this Agreement. Such notice shall be made in writing within 10 working days of the sale, transfer, or other change in ownership and shall identify any new owner or operator with sufficient detail to allow the Commission to immediately contact said new owner or operator.
11. Koch represents that those facts or circumstances which were identified by the Review conducted by the Pipeline Safety Section of the Commission's Gas Services Division, and which were noted as alleged violations under the jurisdiction of the Commission, have now been addressed and/or corrected such that those facilities and systems for which those facts and circumstances were identified, are fully in compliance with all applicable laws and Commission rules.
12. The Pipeline Safety Section of the Commission's Gas Services Division is directed to promptly determine whether such alleged violations, which are under the jurisdiction of the Commission, have been brought into compliance and remain in compliance at the time of the determination.
13. An administrative penalty in the amount of TWENTY-TWO THOUSAND FIVE HUNDRED DOLLARS (\$22,500.00) shall be recovered by the Commission for the alleged violations committed by Koch, as the owner and/or operator of the Hazardous Liquid System/Corpus, the Koch PL/Corpus Christi, the Koch PL/Medford, and the Koch Ref. LP/Corpus Christi units.
14. Koch has placed in the possession or has caused to be placed in the possession of the Commission, funds in the amount of TWENTY-TWO THOUSAND FIVE HUNDRED DOLLARS (\$22,500.00) for deposit in the General Revenue Fund, as payment of administrative penalties to be assessed in Gas Utilities Docket No. 8869.

EXHIBIT NO. 6
VIOLATIONS BY JURISDICTION



RRCII 00926

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Koch Pipeline Special Investigation

RRCII 02192

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- B. MILES OF PIPELINE INSPECTED BY PRODUCTS TRANSPORTED**
- C. MILES OF PIPELINE INSPECTED BY JURISDICTION**
- D. PREVIOUS OPERATORS OF PIPELINE INSPECTED**
- E. LEAK HISTORY**
- F. VIOLATION SUMMARY**
- G. VIOLATION LISTINGS**
- H. TIME EXPENDED FOR INVESTIGATION**

RRCII 02194

Miles of Pipeline Permitted and Inspected

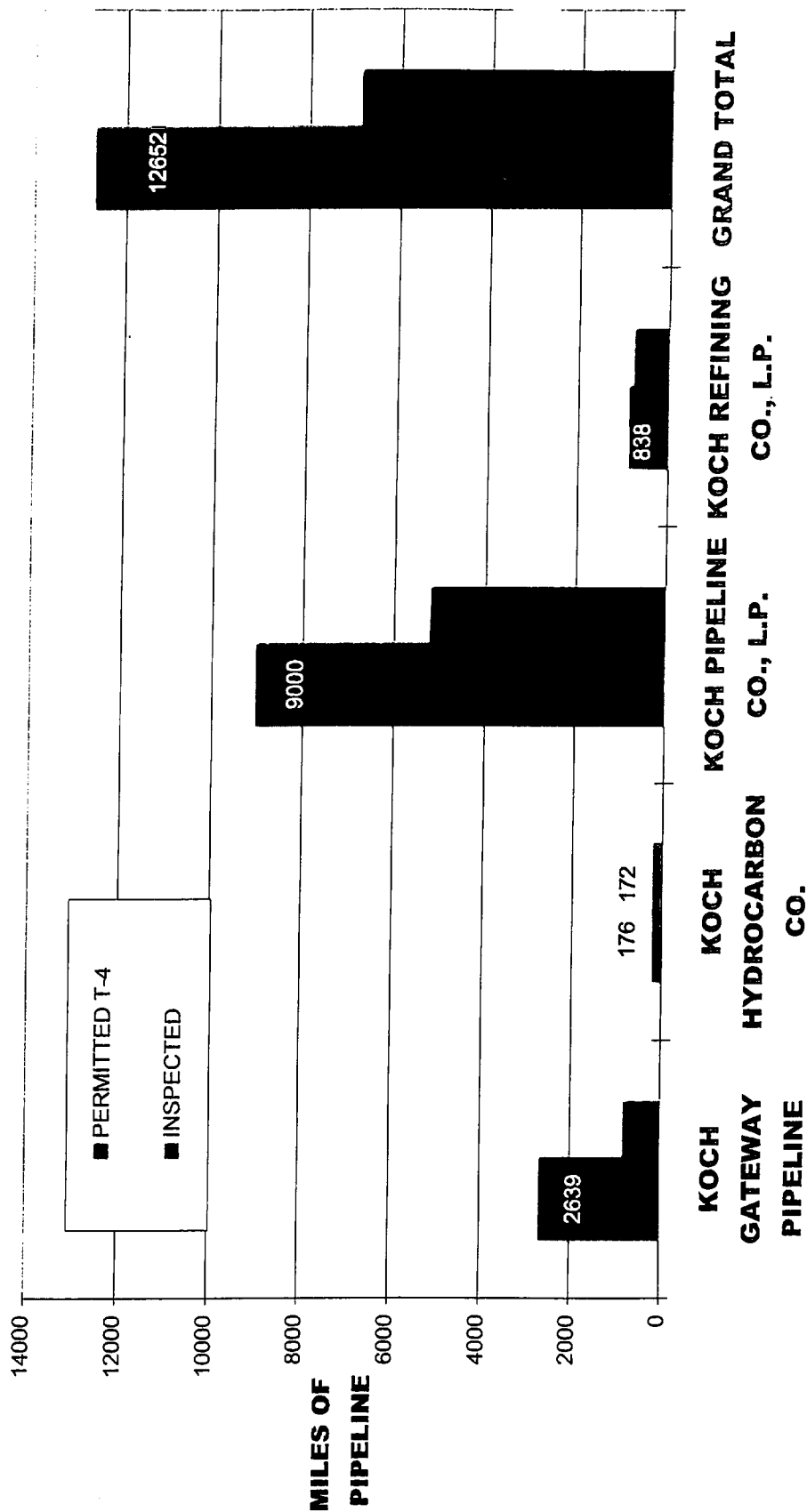
RRCII 02195

MILEAGE REPORT

<u>OPERATOR</u>	<u>T-4</u>	<u>MILES PERMIT</u>	<u>ACTIVE/INACTIVE</u>
Koch Energy Service Company	05382	603.9	ACTIVE
KOCH ENERGY SERVICES COMPANY (1 detail record)			
Subtotal.....		603.9	
Koch Gateway Pipeline Company	00761	2639	ACTIVE
	04136	0	ACTIVE
KOCH GATEWAY PIPELINE COMPANY (2 detail records)			
Subtotal.....		2639	
Koch Hydrocarbon Pipeline Co.	01031	3.3	ACTIVE
	01438	172	ACTIVE
	03974	0.5	ACTIVE
KOCH HYDROCARBON CO. (3 detail records)			
Subtotal.....		175.8	
Koch Pipeline Company, L.P.	00140	5560.9	ACTIVE
	00561	829.4	ACTIVE
	00806	50.3	ACTIVE
	01700	285.5	ACTIVE
	01992	601.8	ACTIVE
	02858	80.2	ACTIVE
	04139	4.6	ACTIVE
	04518	309.7	ACTIVE
	04592	3.7	ACTIVE
	04638	454.1	ACTIVE
	04715	150	ACTIVE
	04789	326	INACTIVE
	04836	81.6	ACTIVE
	04932	261.28	ACTIVE
KOCH PIPELINE COMPANY, L.P. (14 detail records)			
Subtotal.....		8999.08	
Koch Refining Company, L.P.	04015	568.4	ACTIVE
	04956	209.5	ACTIVE
	05223	2.7	ACTIVE
	05411	7.5	ACTIVE
	05412	7.5	ACTIVE
	05413	7	ACTIVE
	05414	7	ACTIVE
	05419	7	ACTIVE
	05420	7	ACTIVE
	05421	7	ACTIVE
	05422	7	ACTIVE
KOCH REFINING COMPANY, L.P. (11 detail records)			
Subtotal.....		837.6	
GRAND TOTAL.....		13255.38	

RRCII 02196

PERMITTED VS INSPECTED



Miles of Pipe Inspected by T-4 Permit No.

Permit No: 00140

KOCH PIPELINE CO., L.P.

HAZARDOUS LIQUID SYSTEMS/CORPUS

sysid	sysname	Sum Of Miles
752125	FALLS CITY STATION TO PETTUS 6"	32.3
Summary for 'ocname' = HAZARDOUS LIQUID SYSTEMS/CORPUS (1 detail record)		
Sum		32.3

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Miles
451173	SHAFT TO HEARNE STA.	21.3
451174	SHAFT TO GERDES	23.6
451175	CALDWELL 6"	4.3
451176	WEST POINT TO THREE WAY	3.0
451177	ZOCH LOOP 6"	8.4
451178	GERDES TO THREE WAY TRAP	32.3
451179	THREE WAY TRAP TO ROSANKY STATION	12.4
451180	ROSAKNY STATION TO NIXON	55.8
451181	NIXON TO PETTUS	45.9
750120	EAST WHITE POINT 10"	5.2
750183	KRC 12"	4.0
750185	VIOLA CRUDE PIPELINE #1	24.5
750188	KRC BURNER CARGO	7.0
750194	VIOLA 16"	32.4
750196	CRUDE/RATTLESNAKE 10"-12"	542.9
750199	LAMBERT 10" CRUDE PIPELINE	4.1
750202	PEARSALL-DILLEY 10"	76.8
750207	AGUA DULCE 10"	29.0
750209	MAYO 10"	28.0

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750213	VIOLA	1.0
751675	KRC OXY PROPANE 4" PIPELINE	3.5
751771	KRC EAST 8"	5.0
751852	KRC EAST 10"	6.7
751920	INGLESIDE JCT. 12"	28.0
752113	BENAVIDES #1 T/I 4"	3.9
752114	CASO CARGO	7.0
752115	8" LPG P/L	7.0
752116	REFUGIO 12" CRUDE PIPELINE	29.5
752117	LEOPARD #2	48.1
752118	THREE RIVERS	62.4
752120	KRC 6" & 8" PROPYLENE/PROPANE	8.0
752123	TIVOLI 3.5	4.5
752128	SUN FIELD STATION	1.4
752130	MIRANDO DUVAL MAINLINE 8"	38.0
851239	INGELSIDE 8" RHC	28.2
851240	REFUGIO 8" RHC	7.1
851241	FANNIE HEARD	5.3
851242	LAKE PASTURE	0.8
851243	NEW QUINTANA PUMP STATION	0.8
851244	DEFENSE	10.0
851245	NQ STA 6	2.4
851246	NQ STATION	1.5
851247	LAMBERT STA	1.0
851248	CLAUDE HEARDE	0.8
851249	LAMBERT PEN	0.7
851250	KOCH PL LP	0.6
851251	LAMBERT STATION	0.5
851252	RLC MAIN	0.4
851253	O'CONNOR A TO NQ "Y" RLC	0.4

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851254	NQ STATION 6"	0.4
851255	O'CONNER GAS PLANT	0.3
851256	#4 TIE IN 6"-RLC	0.2
851257	LAKE PASTURE 4" LOOP -RLC	12.8
851258	F JCT. RLC	4.6
851259	MELON 1 & 2 TO LAMBERT 8" RHC	2.1
851260	REFUGIO STA. 6" RLC	3.0
851261	MELON 1 & 2 TO LAMBERT 4" RHC	1.8
851262	LAMBERT STA-RLC	1.7
851263	HWY 136 4"	1.6
851264	GRETA 4"-RHC	1.6
851265	REFUGIO EL OSO 4" RLC	1.5
851266	NQ STA 4"-RLC	1.4
851267	COPANO E2 TO COPANO Y JCT-RLC	1.3
851268	COPANO B1 & E3 TO COPANO Y JCT-RLC	1.2
851269	LAMBERT C INJECTION TO LAMBERT 10" RHC	1.2
851270	PENNZOIL C TO NQ - LAMBERT 10" RHC	1.2
851271	C PUMP RLC	1.0
851272	TCG 2 TIE IN-RHC	1.0
851273	LAKE PASTURE 4" LOOP-RHC	1.0
851274	REFUGIO N & S TO CITATION ME O'CONNOR	0.9
851275	TCGI LEASE 4" RHC	0.9
851276	TCGI-RLC	0.9
851277	LENORE JOSIE TO GRETA 4" RHC	0.8
851278	NQ COPANO D TO NQ "Y" RLC, 4"	0.8
851279	5800 #1 TO COPANO Y JCT-RLC	0.8
851280	CLAUDE HEARD RLC	0.7
851281	LAKE PASTURE 4" LOOP	0.6
851282	MAUDE A-RLC	0.6
851283	O'CONNOR C JCT. RLC, 4"	0.6

851284	NQ STA. 4" RLC	0.6
851285	ILAMBERT10 " RHC	0.6
851286	NQ LAMBERT 10"-RHC	0.6
851287	LAMBERT H&D O RHC	0.6
851288	FANNIE HEARD TO GRETA 4" RHC	0.5
851289	LAMBERT RHC	0.5
851290	B1 RLC	0.5
851291	H&D B JCT.-RLC	0.5
851292	REFUGIO 6"-RLC	0.4
851293	5800 T/I-RLC	0.4
851294	MAUDE A L/P RLC	0.4
851295	COPANO NORDEN & MORRIS LATERAL RLC	0.3
851296	C PUMP	0.3
851297	JB HEARD 4" RHC	0.3
851298	GRETA 6"-RHC	0.1
851299	5800 #2 T/I RLC	0.1
851300	REFUGIO STA.-RLC	5.5
851301	REFUGIO B1 TO CITATION ME O'CONNER	2.1
851313	POWERS STA. 8"	39.1
851314	PETTUS 6"	13.6
851315	WEIGANG GATHERING	1.0
851316	FALLS CITY STA.	1.8
851317	SEELIGSON STATION -8"	50.8
851318	YUTTERIA 6"	21.0
851319	KELSEY 6"	11.0
851320	SUN FIELD STA.	1.0
851321	GARCIA MAIN GATHERING 4"	19.5
851322	SUN FIELD STATION	17.0
851323	MONTE CRISTO GATHERING	14.8
851324	SHELL-LOPEZ-4"	10.0

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851326	YUTTERIA GATHERING	5.9
851327	THREE RIVERS 6"	16.8
851328	N. TILDEN 6"	0.9
851329	MIRANDO	27.3
851330	TILDEN STA.	6.1
851331	GRANT WILLIAMS (A)	3.8
851332	TILDEN 6", 4"	2.1
851333	WC RUTHERFORD 4"	1.2
851334	LA BILLINGS TO N. TILDEN	0.4
851335	GRANT WILLIAMS A TO LA BILLINGS TO N. TILDEN	1.8
851336	N. TILDEN GATHERING 3"	0.8
851337	#1 LEE WHEELER TO LA BILLING TO N. TILDEN, 3"	0.6
851338	N. WHEELER TO TILDEN 6"	0.5
851339	HO TAYLOR TO TILDEN 6"	0.9
851340	PONTIAC 8" PORTILLA LINE	10.0
851341	12" RLC TIE-IN	32.0
851342	TIVOLI 6"	11.4
851343	HEYSER STA 6"	5.4
851344	HEYSER STA. 4"	4.0
851345	N. TILDEN GATHERING 4"	6.1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (129 detail records)
Sum

1677.0

KOCH PL / LONGVIEW

sysid	sysname	Sum Of Miles
351749	MAINLINE	5.4
351750	ADD'L LATERALS OFF MAINLINE	3.8
351751	THRASHER GATHERING	2.1
351752	LACY-SNYDER GATHERING	3.6
351753	SNODDY GATHERING	5.3
351754	KEY CORNER GATHERING	3.3
351755	INGRAM GATHERING	3.7

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351756	ANDERSON GATHERING	4.4
351758	RODDEN GATHERING	2.7
351759	FISHER GATHERING	11.8
351762	HARRIS-NORTON MAINLINE	7.5
351763	STINCHCOMB TRUNKLINE	3.5
351767	SMITH-EXXON 3"	0.1
851347	POWELL GATHERING	3.7
851348	MOBIL-SNODDY GATHERING	1.1
851361	GLADEWATER GATHERING	10.3
851362	MOBIL GATHERING	4.0
851363	MIDDLE 1/3	39.8
851364	MIDDLE 1/3 BP, KOCH	9.3
851365	MONDAY LEG	9.1
851366	NORTH 1/3 GATHERING	33.5
851367	LAKE DIVERNIA LEG	4.5
851368	SOUTH 1/3 BP, KOCH	4.9
851369	SOUTH 1/3	14.7
Summary for 'ocname' = KOCH PL / LONGVIEW (24 detail records)		192.1
Sum		
KOCH PL / MEDFORD		
sysid	sysname	Sum Of Miles
551956	NEEDERLAND 8"	64.0
650199	EP MIX/CHICO-FARMERSVILLE 4", 6"	92.6
651440	SOUTHLAKE 12"	12.0
651441	DFW 8"	8.1
752126	SOUR LAKE STA. 8"	11.0
752127	ARRIOLA STA NO. 2, 6"	0.5
Summary for 'ocname' = KOCH PL / MEDFORD (6 detail records)		188.2
Sum		
Summary for 'opname' = KOCH PIPELINE CO., L.P. (160 detail records)		2089.6
Sum		
Summary for 't4no' = 00140 (160 detail records)		2089.6
Sum		

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Permit No: 00561**KOCH PIPELINE CO., L.P.****KOCH PL / MEDFORD**

sysid	sysname	Sum Of Miles
851226	GAINESVILLE, SHERMAN LEG	27.8
851227	GAINESVILLE, BEST DISCH.	9.4
851228	GAINESVILLE, NOCONA LEG	25.6
851229	CRUDE/MUENSTER	31.2
950001	GAINESVILLE	356.0
950002	BRECKENRIDGE	75.0
950003	HASKELL	333.7
950004	MCELROY (OR AMACKER)	112.0
950005	QUITO (OR HENDRICKS)	57.7
950006	ACKERLEY (OR GOOD)	19.4
950007	DRIVER	3.5
950008	PARDUE	3.3
950009	STONEWALL (EAST HAMLIN)	31.6
950010	UPTON (OR BENEDUM)	11.3
950011	GARZA	15.7
950012	TRENT	20.8
Summary for 'ocname' = KOCH PL / MEDFORD (16 detail records)		
Sum		1134.0

KOCH PL / MIDLAND

sysid	sysname	Sum Of Miles
851221	GARZA SYS.	63.0
851222	HASKELL (WEST LEG)	95.8
851223	PARDUE	12.5
851224	STONEWALL GATH. SYSTEM	34.6
851225	TRENT	19.4
851230	MCELROY GATHERING	23.0

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RRCII 02204

851231	QUITO CRUDE GATHERING	26.6
851232	DRIVER GATHERING	39.0
851233	UPTON CRUDE GATHERING	8.0
851346	CHAPARRAL PIPELINE	565.1
Summary for 'ocname' = KOCH PL / MIDLAND (10 detail records)		
Sum		887.0
Summary for 'opname' = KOCH PIPELINE CO., L.P. (26 detail records)		
Sum		2021.0
Summary for 't4no' = 00561 (26 detail records)		
Sum		2021.0

Permit No: 00761

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	Sum Of Miles
831234	TPL-059 CARTHAGE	112.9
831235	TPL-63 CARTHAGE	31.8
831236	TPL-92 CARTHAGE	4.2
831237	T-266 CARTHAGE TO STERLINGTON	17.2
831238	391-02-01 CARTHAGE	24.5
831302	TPL-264 CARTHAGE	0.2
831303	TPL-265 CARTHAGE	4.1
831304	TPL-213 CARTHAGE	1.6
831305	TPL-263 CARTHAGE	3.8
831306	TPL-212 CARTHAGE	6.9
831307	TPL-173 CARTHAGE	4.3
831308	TPL-86 CARTHAGE	1.3
831309	TPL 66-CARTHAGE	1.8
831310	TPL-65 CARTHAGE	1.8
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (14 detail records)		
Sum		216.6

KOCH GATEWAY/LONGVIEW

sysid	sysname	Sum Of Miles
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831349	TPL-391 LONGVIEW	21.3
831350	TPL-10 LONGVIEW	11.8
831351	TPL-65-2 LONGVIEW	18.8
831352	TPL-430 LONGVIEW	57.1
831353	TPL-11 LONGVIEW	121.9
831354	TPL-8 LONGVIEW	71.7
831355	TPL-178 LONGVIEW	0.1
831356	TPL-1 LONGVIEW	252.0
831357	TPL-6 LONGVIEW	4.3
831358	TPL-4-LONGVIEW	9.6

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (10 detail records)

Sum

568.7

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (24 detail records)

Sum

785.2

KOCH PIPELINE CO., L.P.

KOCH PL / MIDLAND

sysid	sysname	Sum Of Miles
851220	ACKERLEY	14.4
Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)		
Sum		14.4
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		14.4
Summary for 't4no' = 00761 (25 detail records)		
Sum		799.6

Permit No: 01438

KOCH HYDROCARBON COMPANY

KOCH HYDROCARBON/MIDLAND

sysid	sysname	Sum Of Miles
250711	NGL/SONORA TO ROBERT RANCH	172.0
Summary for 'ocname' = KOCH HYDROCARBON/MIDLAND (1 detail record)		
Sum		172.0
Summary for 'opname' = KOCH HYDROCARBON COMPANY (1 detail record)		
Sum		172.0
Summary for 't4no' = 01438 (1 detail record)		
Sum		172.0

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Permit No: 01700**KOCH PIPELINE CO., L.P.****KOCH PL / MEDFORD**

sysid	sysname	Sum Of Miles
851360	TEXAS FERC	297.6
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)		
Sum		297.6
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		297.6
Summary for 't4no' = 01700 (1 detail record)		
Sum		297.6

Permit No: 02858**KOCH PIPELINE CO., L.P.****KOCH PL / CORPUS CHRISTI**

sysid	sysname	Sum Of Miles
450938	MARLIN TO TEMPLE 4" (SOUTHWEST PIPELINE)	38.6
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)		
Sum		38.6
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		38.6
Summary for 't4no' = 02858 (1 detail record)		
Sum		38.6

Permit No: 04015**KOCH REFINING COMPANY, L.P.****KOCH REF. LP / CORPUS CHRISTI**

sysid	sysname	Sum Of Miles
451137	TP1-SAN ANTONIO TO AUSTIN	95.0
451141	TP1-AUSTIN TO WACO	110.0
652087	TP11-WACO TO EULESS	106.0
751981	TP1-CORPUS TO SAN ANTONIO	134.5
Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (4 detail records)		
Sum		445.5

Summary for 'opname' = KOCH REFINING COMPANY, L.P. (4 detail records)

Sum 445.5

Summary for 't4no' = 04015 (4 detail records)

Sum 445.5

Permit No: 04139

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Miles
450937	STAR 8"	3.2
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)		
Sum		3.2
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		3.2
Summary for 't4no' = 04139 (1 detail record)		
Sum		3.2

Permit No: 04518

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

sysid	sysname	Sum Of Miles
851311	STERLING II	309.7
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)		
Sum		309.7
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		309.7
Summary for 't4no' = 04518 (1 detail record)		
Sum		309.7

Permit No: 04592

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Miles
731687	KRC OXY HYDROGEN 6"/10" PIPELINE	2.6
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)		
Sum		2.6
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		2.6

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Summary for 't4no' = 04592 (1 detail record)
Sum

2.6

Permit No: 04638

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

sysid	sysname	Sum Of Miles
851359	MCCAMEY	317.3
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)		
Sum		317.3
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		317.3
Summary for 't4no' = 04638 (1 detail record)		
Sum		317.3

Permit No: 04836

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Miles
752119	MAYO	62.1
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)		
Sum		62.1
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)		
Sum		62.1
Summary for 't4no' = 04836 (1 detail record)		
Sum		62.1

Permit No: 04956

KOCH REFINING COMPANY, L.P.

KOCH REF. LP / CORPUS CHRISTI

sysid	sysname	Sum Of Miles
451139	TPL #2-GONZALES TO WACO	141.0
751982	TPL #2 CORPUS TO GONZALES	136.0
Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (2 detail records)		
Sum		277.0
Summary for 'opname' = KOCH REFINING COMPANY, L.P. (2 detail records)		
Sum		277.0

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Summary for 't4no' = 04956 (2 detail records)
Sum

277.0

Grand Total

6835.9

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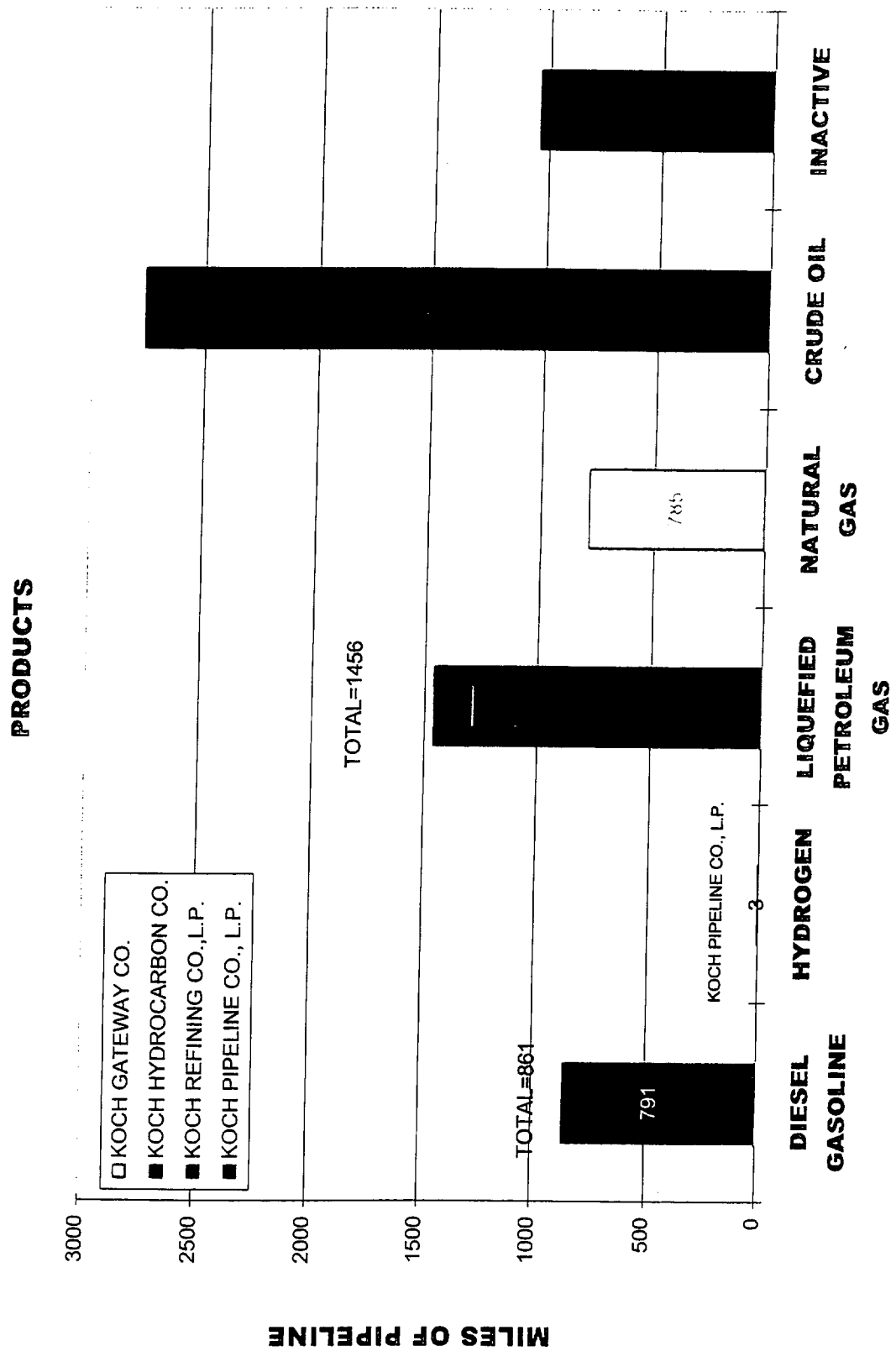
RRCH 02210

B

RRCH 02211

Miles of Pipeline Inspected
by
Products Transported

RRCII 02212



RRCH 02213

Miles of Pipe by Product Transported

Gasoline, Diesel

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

jur	reg	sysid	sysname	Sum Of Miles
I	R	450937	STAR 8"	3.2
I	R	450938	MARLIN TO TEMPLE 4" (SOUTHWEST PIPELINE)	38.6
I	R	752114	CASO CARGO	7.0
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (3 detail records)				
Sum				48.8

KOCH PL / MEDFORD

jur	reg	sysid	sysname	Sum Of Miles
I	R	651440	SOUTHLAKE 12"	12.0
I	R	651441	DFW 8"	8.1
Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				
Sum				20.1
Summary for 'opname' = KOCH PIPELINE CO., L.P. (5 detail records)				
Sum				68.9

KOCH REFINING COMPANY, L.P.

KOCH REF. LP / CORPUS CHRISTI

jur	reg	sysid	sysname	Sum Of Miles
I	R	751982	TPL #2 CORPUS TO GONZALES	136.0
I	R	451137	TP1-SAN ANTONIO TO AUSTIN	95.0
I	R	451139	TPL #2-GONZALES TO WACO	141.0
I	R	451141	TP1-AUSTIN TO WACO	110.0

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I	R	652087	TPII-WACO TO EULESS	106.0
I	R	751981	TP1-CORPUS TO SAN ANTONIO	134.5

Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (6 detail records)

Sum	722.5
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Summary for 'opname' = KOCH REFINING COMPANY, L.P. (6 detail records)

Sum	722.5
-----	-------

Summary for 'product' = Gasoline, Diesel (11 detail records)

Sum	791.4
-----	-------

Hydrogen

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

jur	req	sysid	sysname	Sum Of Miles
I	R	731687	KRC OXY HYDROGEN 6"/10" PIPELINE	2.6

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)

Sum	2.6
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Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)

Sum	2.6
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Summary for 'product' = Hydrogen (1 detail record)

Sum	2.6
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Inactive

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

jur	req	sysid	sysname	Sum Of Miles
I	N	950012	TRENT	20.8
I	N	950005	QUITO (OR HENDRICKS)	57.7
I	N	950001	GAINESVILLE	356.0
I	N	950003	HASKELL	333.7
I	N	950006	ACKERLEY (OR GOOD)	19.4
I	N	950007	DRIVER	3.5

I	N	950008	PARDUE	3.3
I	N	950009	STONEWALL (EAST HAMLIN)	31.6
I	N	950011	GARZA	15.7
I	N	950002	BRECKENRIDGE	75.0
I	N	950010	UPTON (OR BENEDUM)	11.3
I	N	950004	MCELROY (OR AMACKER)	112.0

Summary for 'ocname' = KOCH PL / MEDFORD (12 detail records)

Sum 1040.1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (12 detail records)

Sum 1040.1

Summary for 'product' = Inactive (12 detail records)

Sum 1040.1

Liquefied Petroleum Gas

KOCH HYDROCARBON COMPANY

KOCH HYDROCARBON/MIDLAND

jur	reg	sysid	sysname	Sum Of Miles
I	R	250711	NGL/SONORA TO ROBERT RANCH	172.0

Summary for 'ocname' = KOCH HYDROCARBON/MIDLAND (1 detail record)

Sum 172.0

Summary for 'opname' = KOCH HYDROCARBON COMPANY (1 detail record)

Sum 172.0

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

jur	reg	sysid	sysname	Sum Of Miles
I	R	752120	KRC 6" & 8" PROPYLENE/PROPANE	8.0
I	R	752115	8" LPG P/L	7.0
I	R	751675	KRC OXY PROPANE 4" PIPELINE	3.5

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (3 detail records)

Sum 18.5

KOCH PL / MEDFORD

jur	req	sysid	sysname	Sum Of Miles
I	R	650199	EP MIX/CHICO-FARMERSVILLE 4", 6"	92.6
O	R	851311	STERLING II	309.7
O	R	851360	TEXAS FERC	297.6

Summary for 'ocname' = KOCH PL / MEDFORD (3 detail records)

Sum 700.0

KOCH PL / MIDLAND

jur	req	sysid	sysname	Sum Of Miles
O	R	851346	CHAPARRAL PIPELINE	565.1

Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)

Sum 565.1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (7 detail records)

Sum 1283.6

Summary for 'product' = Liquefied Petroleum Gas (8 detail records)

Sum 1455.5

Natural Gas

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

jur	req	sysid	sysname	Sum Of Miles
O	R	831235	TPL-63 CARTHAGE	31.8
O	R	831305	TPL-263 CARTHAGE	3.8
O	R	831234	TPL-059 CARTHAGE	112.9
O	R	831307	TPL-173 CARTHAGE	4.3
O	R	831238	391-02-01 CARTHAGE	24.5
O	R	831302	TPL-264 CARTHAGE	0.2

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O	R	831304	TPL-213 CARTHAGE	1.6
O	R	831237	T-266 CARTHAGE TO STERLINGTON	17.2
O	R	831306	TPL-212 CARTHAGE	6.9
O	R	831236	TPL-92 CARTHAGE	4.2
O	R	831309	TPL 66-CARTHAGE	1.8
O	R	831310	TPL-65 CARTHAGE	1.8
O	R	831303	TPL-265 CARTHAGE	4.1
O	R	831308	TPL-86 CARTHAGE	1.3

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (14 detail records)

Sum 216.6

KOCH GATEWAY/LONGVIEW

jur	req	sysid	sysname	Sum Of Miles
O	R	831352	TPL-430 LONGVIEW	57.1
O	R	831358	TPL-4-LONGVIEW	9.6
O	R	831357	TPL-6 LONGVIEW	4.3
O	R	831356	TPL-1 LONGVIEW	252.0
O	R	831355	TPL-178 LONGVIEW	0.1
O	R	831350	TPL-10 LONGVIEW	11.8
O	R	831349	TPL-391 LONGVIEW	21.3
O	R	831354	TPL-8 LONGVIEW	71.7
O	R	831353	TPL-11 LONGVIEW	121.9
O	R	831351	TPL-65-2 LONGVIEW	18.8

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (10 detail records)

Sum 568.7

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (24 detail records)

Sum 785.2

Summary for 'product' = Natural Gas (24 detail records)

Sum 785.2

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Petroleum Crude Oil**KOCH PIPELINE CO., L.P.****HAZARDOUS LIQUID SYSTEMS/CORPUS**

jur	req	sysid	sysname	Sum Of Miles
I	R	752125	FALLS CITY STATION TO PETTUS 6"	32.3
Summary for 'ocname' = HAZARDOUS LIQUID SYSTEMS/CORPUS (1 detail record)				
Sum				32.3

KOCH PL / CORPUS CHRISTI

jur	req	sysid	sysname	Sum Of Miles
I	N	851253	O'CONNOR A TO NQ "Y" RLC	0.4
I	N	851258	F JCT. RLC	4.6
I	N	851257	LAKE PASTURE 4" LOOP -RLC	12.8
I	N	851256	#4 TIE IN 6"-RLC	0.2
I	N	851254	NQ STATION 6"	0.4
I	N	851252	RLC MAIN	0.4
I	N	851251	LAMBERT STATION	0.5
I	N	851259	MELON 1 & 2 TO LAMBERT 8" RHC	2.1
I	N	851250	KOCH PL LP	0.6
I	N	851255	O'CONNER GAS PLANT	0.3
I	N	851260	REFUGIO STA. 6" RLC	3.0
I	N	851262	LAMBERT STA-RLC	1.7
I	N	851264	GRETA 4"-RHC	1.6
I	N	851265	REFUGIO EL OSO 4" RLC	1.5
I	N	851266	NQ STA 4"-RLC	1.4
I	N	851267	COPANO E2 TO COPANO Y JCT-RLC	1.3

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I	N	851268	COPANO B1 & E3 TO COPANO Y JCT-RLC	1.2
I	N	851269	LAMBERT C INJECTION TO LAMBERT 10" RHC	1.2
I	N	851271	C PUMP RLC	1.0
I	N	851249	LAMBERT PEN	0.7
I	N	851270	PENNZOIL C TO NQ - LAMBERT 10" RHC	1.2
I	N	752128	SUN FIELD STATION	1.4
I	N	851263	HWY 136 4"	1.6
I	N	451173	SHAFT TO HEARNE STA.	21.3
I	N	851272	TCG 2 TIE IN-RHC	1.0
I	N	451175	CALDWELL 6"	4.3
I	N	451176	WEST POINT TO THREE WAY	3.0
I	N	451177	ZOCH LOOP 6"	8.4
I	N	451178	GERDES TO THREE WAY TRAP	32.3
I	N	451179	THREE WAY TRAP TO ROSANKY STATION	12.4
I	N	451180	ROSAKNY STATION TO NIXON	55.8
I	N	451174	SHAFT TO GERDES	23.6
I	N	752123	TIVOLI 3.5	4.5
I	N	851248	CLAUDE HEARDE	0.8
I	N	752130	MIRANDO DUVAL MAINLINE 8"	38.0
I	N	851239	INGELSIDE 8" RHC	28.2
I	N	851240	REFUGIO 8" RHC	7.1
I	N	851241	FANNIE HEARD	5.3
I	N	851242	LAKE PASTURE	0.8
I	N	851243	NEW QUINTANA PUMP STATION	0.8
I	N	851244	DEFENSE	10.0
I	N	851245	NQ STA 6	2.4

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I	N	851246	NQ STATION	1.5
I	N	851247	LAMBERT STA	1.0
I	N	451181	NIXON TO PETTUS	45.9
I	N	851332	TILDEN 6", 4"	2.1
I	N	851316	FALLS CITY STA.	1.8
I	N	851317	SEELIGSON STATION -8"	50.8
I	N	851318	YUTTERIA 6"	21.0
I	N	851319	KELSEY 6"	11.0
I	N	851320	SUN FIELD STA.	1.0
I	N	851321	GARCIA MAIN GATHERING 4"	19.5
I	N	851322	SUN FIELD STATION	17.0
I	N	851323	MONTE CRISTO GATHERING	14.8
I	N	851324	SHELL-LOPEZ-4"	10.0
I	N	851273	LAKE PASTURE 4" LOOP-RHC	1.0
I	N	851327	THREE RIVERS 6"	16.8
I	N	851261	MELON 1 & 2 TO LAMBERT 4" RHC	1.8
I	N	851329	MIRANDO	27.3
I	N	851315	WEIGANG GATHERING	1.0
I	N	851338	N. WHEELER TO TILDEN 6"	0.5
I	N	851345	N. TILDEN GATHERING 4"	6.1
I	N	851344	HEYSER STA. 4"	4.0
I	N	851343	HEYSER STA 6"	5.4
I	N	851342	TIVOLI 6"	11.4
I	N	851341	12" RLC TIE-IN	32.0
I	N	851330	TILDEN STA.	6.1
I	N	851339	HO TAYLOR TO TILDEN 6"	0.9

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I	N	851331	GRANT WILLIAMS (A)	3.8
I	N	851337	#1 LEE WHEELER TO LA BILLING TO N. TILDEN, 3"	0.6
I	N	851336	N. TILDEN GATHERING 3"	0.8
I	N	851335	GRANT WILLIAMS A TO LA BILLINGS TO N. TILDEN	1.8
I	N	851334	LA BILLINGS TO N. TILDEN	0.4
I	N	851333	WC RUTHERFORD 4"	1.2
I	N	851326	YUTTERIA GATHERING	5.9
I	N	851340	PONTIAC 8" PORTILLA LINE	10.0
I	N	851282	MAUDE A-RLC	0.6
I	N	851292	REFUGIO 6"-RLC	0.4
I	N	851291	H&D B JCT.-RLC	0.5
I	N	851290	B1 RLC	0.5
I	N	851289	LAMBERT RHC	0.5
I	N	851288	FANNIE HEARD TO GRETA 4" RHC	0.5
I	N	851287	LAMBERT H&D O RHC	0.6
I	N	851286	NQ LAMBERT 10"-RHC	0.6
I	N	851285	ILAMBERT10 " RHC	0.6
I	N	851293	5800 T/I-RLC	0.4
I	N	851283	O'CONNOR C JCT. RLC, 4"	0.6
I	N	851277	LENORE JOSIE TO GRETA 4" RHC	0.8
I	N	851281	LAKE PASTURE 4" LOOP	0.6
I	N	851280	CLAUDE HEARD RLC	0.7
I	N	851279	5800 #1 TO COPANO Y JCT-RLC	0.8
I	N	851278	NQ COPANO D TO NQ "Y" RLC, 4"	0.8
I	N	851314	PETTUS 6"	13.6
I	N	851276	TCGI-RLC	0.9

I	N	851328	N. TILDEN 6"	0.9
I	N	851274	REFUGIO N & S TO CITATION ME O"CONNOR	0.9
I	N	851284	NQ STA. 4" RLC	0.6
I	N	851297	JB HEARD 4" RHC	0.3
I	N	851275	TCGI LEASE 4" RHC	0.9
I	N	851313	POWERS STA. 8"	39.1
I	N	851301	REFUGIO B1 TO CITATION ME O'CONNER	2.1
I	N	851300	REFUGIO STA.-RLC	5.5
I	N	851299	5800 #2 T/I RLC	0.1
I	N	851298	GRETA 6"-RHC	0.1
I	N	851294	MAUDE A L/P RLC	0.4
I	N	851296	C PUMP	0.3
I	N	851295	COPANO NORDEN & MORRIS LATERAL RLC	0.3
I	R	750202	PEARSALL-DILLEY 10"	76.8
I	R	752118	THREE RIVERS	62.4
I	R	752117	LEOPARD #2	48.1
I	R	752116	REFUGIO 12" CRUDE PIPELINE	29.5
I	R	752113	BENAVIDES #1 T/I 4"	3.9
I	R	750183	KRC 12"	4.0
I	R	750199	LAMBERT 10" CRUDE PIPELINE	4.1
I	R	752119	MAYO	62.1
I	R	751920	INGLESIDE JCT. 12"	28.0
I	R	750194	VIOLA 16"	32.4
I	R	750196	CRUDE/RATTLESNAKE 10"-12"	542.9
I	R	750185	VIOLA CRUDE PIPELINE #1	24.5
I	R	750120	EAST WHITE POINT 10"	5.2

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I	R	750207	AGUA DULCE 10"	29.0
I	R	750209	MAYO 10"	28.0
I	R	750213	VIOLA	1.0
I	R	751771	KRC EAST 8"	5.0
I	R	751852	KRC EAST 10"	6.7
I	R	750188	KRC BURNER CARGO	7.0

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (126 detail records)

Sum 1713.6

KOCH PL / LONGIVEW

jur	reg	sysid	sysname	Sum Of Miles
I	N	351749	MAINLINE	5.4
I	N	351762	HARRIS-NORTON MAINLINE	7.5
I	N	351767	SMITH-EXXON 3"	0.1
I	N	351750	ADD'L LATERALS OFF MAINLINE	3.8
I	N	351751	THRASHER GATHERING	2.1
I	N	351752	LACY-SNYDER GATHERING	3.6
I	N	351753	SNODDY GATHERING	5.3
I	N	351754	KEY CORNER GATHERING	3.3
I	N	351755	INGRAM GATHERING	3.7
I	N	351756	ANDERSON GATHERING	4.4
I	N	351759	FISHER GATHERING	11.8
I	N	851347	POWELL GATHERING	3.7
I	N	851369	SOUTH 1/3	14.7
I	N	351758	RODDEN GATHERING	2.7
I	N	851348	MOBIL-SNODDY GATHERING	1.1
I	N	851361	GLADEWATER GATHERING	10.3

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I	N	851362	MOBIL GATHERING	4.0
I	N	851363	MIDDLE 1/3	39.8
I	N	851364	MIDDLE 1/3 BP, KOCH	9.3
I	N	851365	MONDAY LEG	9.1
I	N	851366	NORTH 1/3 GATHERING	33.5
I	N	351763	STINCHCOMB TRUNKLINE	3.5
I	N	851368	SOUTH 1/3 BP, KOCH	4.9
I	N	851367	LAKE DIVERNIA LEG	4.5

Summary for 'ocname' = KOCH PL / LONGVIEW (24 detail records)
Sum

192.1

KOCH PL / MEDFORD

jur	req	sysid	sysname	Sum Of Miles
I	N	551956	NEEDERLAND 8"	64.0
I	N	851226	GAINESVILLE, SHERMAN LEG	27.8
I	N	851229	CRUDE/MUENSTER	31.2
I	R	752126	SOUR LAKE STA. 8"	11.0
I	R	752127	ARRIOLA STA NO. 2, 6"	0.5
O	N	851227	GAINESVILLE, BEST DISCH.	9.4
O	N	851228	GAINESVILLE, NOCONA LEG	25.6
O	R	851359	MCCAMEY	317.3

Summary for 'ocname' = KOCH PL / MEDFORD (8 detail records)
Sum

486.8

KOCH PL / MIDLAND

jur	req	sysid	sysname	Sum Of Miles
I	N	851233	UPTON CRUDE GATHERING	8.0
I	N	851232	DRIVER GATHERING	39.0

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I	N	851231	QUITO CRUDE GATHERING	26.6
I	N	851230	MCELROY GATHERING	23.0
I	N	851224	STONEWALL GATH. SYSTEM	34.6
I	N	851223	PARDUE	12.5
I	N	851222	HASKELL (WEST LEG)	95.8
I	N	851221	GARZA SYS.	63.0
I	N	851220	ACKERLEY	14.4
I	N	851225	TRENT	19.4

Summary for 'ocname' = KOCH PL / MIDLAND (10 detail records)

Sum 336.3

Summary for 'opname' = KOCH PIPELINE CO., L.P. (169 detail records)

Sum 2761.1

Summary for 'product' = Petroleum Crude Oil (169 detail records)

Sum 2761.1

Grand Total 6835.9

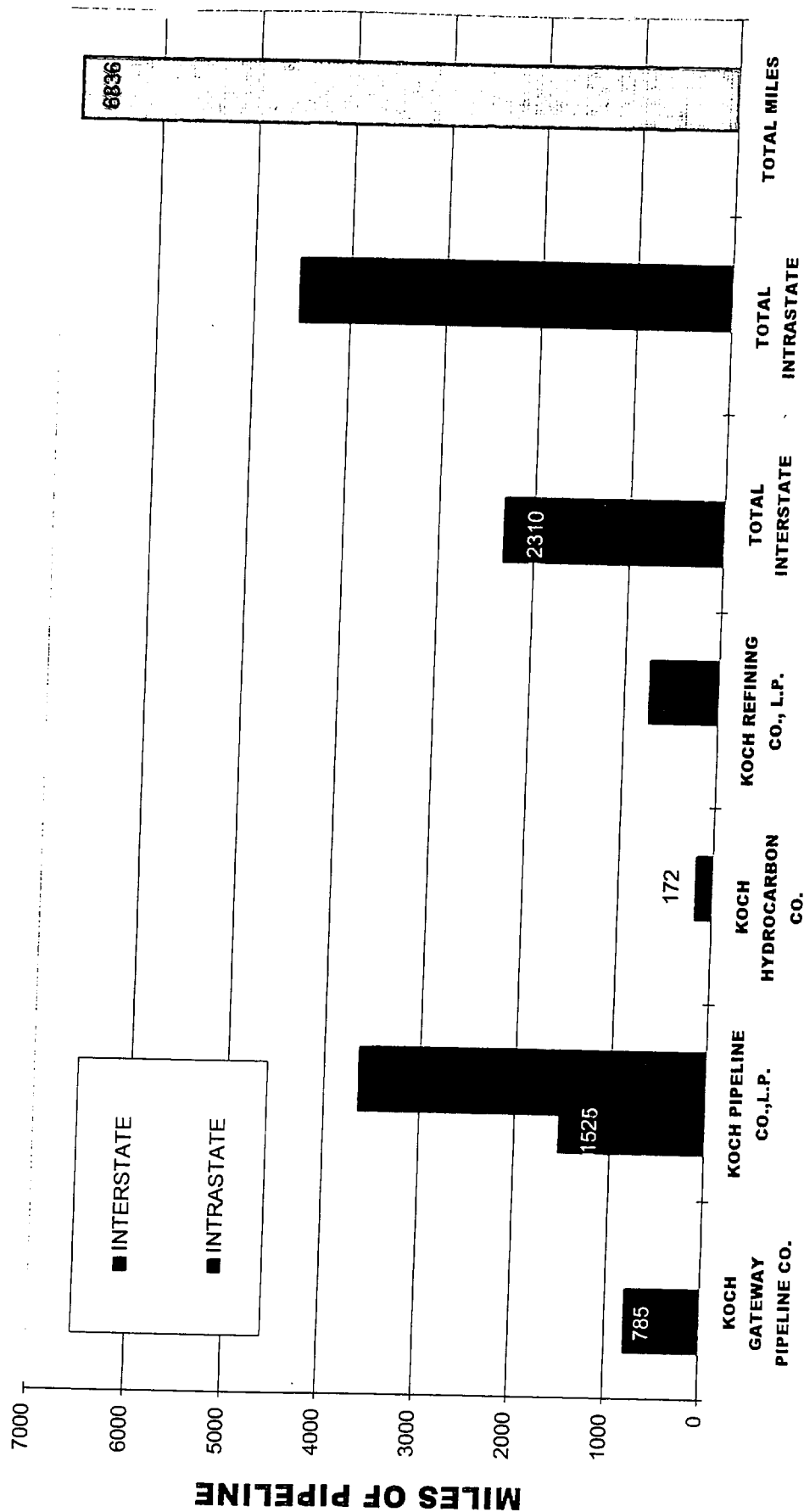
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RRCII 02227

Miles of Pipeline Inspected by Jurisdiction

RRCU 02228

INTERSTATE AND INTRASTATE



RRCII 02229

Miles of Pipe by Jurisdiction

Interstate

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

reg	sysid	sysname	Sum Of Miles
R	831309	TPL 66-CARTHAGE	1.8
R	831310	TPL-65 CARTHAGE	1.8
R	831308	TPL-86 CARTHAGE	1.3
R	831307	TPL-173 CARTHAGE	4.3
R	831306	TPL-212 CARTHAGE	6.9
R	831305	TPL-263 CARTHAGE	3.8
R	831304	TPL-213 CARTHAGE	1.6
R	831302	TPL-264 CARTHAGE	0.2
R	831238	391-02-01 CARTHAGE	24.5
R	831237	T-266 CARTHAGE TO STERLINGTON	17.2
R	831236	TPL-92 CARTHAGE	4.2
R	831235	TPL-63 CARTHAGE	31.8
R	831234	TPL-059 CARTHAGE	112.9
R	831303	TPL-265 CARTHAGE	4.1
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (14 detail records)			
Sum			216.6

KOCH GATEWAY/LONGVIEW

reg	sysid	sysname	Sum Of Miles
R	831350	TPL-10 LONGVIEW	11.8
R	831358	TPL-4-LONGVIEW	9.6
R	831357	TPL-6 LONGVIEW	4.3
R	831356	TPL-1 LONGVIEW	252.0
R	831355	TPL-178 LONGVIEW	0.1

R	831354	TPL-8 LONGVIEW	71.7
R	831353	TPL-11 LONGVIEW	121.9
R	831349	TPL-391 LONGVIEW	21.3
R	831351	TPL-65-2 LONGVIEW	18.8
R	831352	TPL-430 LONGVIEW	57.1

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (10 detail records)

Sum 568.7

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (24 detail records)

Sum 785.2

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

reg	sysid	sysname	Sum Of Miles
N	851228	GAINESVILLE, NOCONA LEG	25.6
N	851227	GAINESVILLE, BEST DISCH.	9.4
R	851359	MCCAMEY	317.3
R	851360	TEXAS FERC	297.6
R	851311	STERLING II	309.7

Summary for 'ocname' = KOCH PL / MEDFORD (5 detail records)

Sum 959.6

KOCH PL / MIDLAND

reg	sysid	sysname	Sum Of Miles
R	851346	CHAPARRAL PIPELINE	565.1

Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)

Sum 565.1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (6 detail records)

Sum 1524.7

Summary for 'jurisdiction' = Interstate (30 detail records)

Sum 2310.0

Intrastate

KOCH HYDROCARBON COMPANY

KOCH HYDROCARBON/MIDLAND

reg	sysid	sysname	Sum Of Miles
R	250711	NGL/SONORA TO ROBERT RANCH	172.0

Summary for 'ocname' = KOCH HYDROCARBON/MIDLAND (1 detail record)

Sum

172.0

Summary for 'opname' = KOCH HYDROCARBON COMPANY (1 detail record)

Sum

172.0

KOCH PIPELINE CO., L.P.**HAZARDOUS LIQUID SYSTEMS/CORPUS**

reg	sysid	sysname	Sum Of Miles
R	752125	FALLS CITY STATION TO PETTUS 6"	32.3

Summary for 'ocname' = HAZARDOUS LIQUID SYSTEMS/CORPUS (1 detail record)

Sum

32.3

KOCH PL / CORPUS CHRISTI

reg	sysid	sysname	Sum Of Miles
N	851269	LAMBERT C INJECTION TO LAMBERT 10" RHC	1.2
N	851268	COPANO B1 & E3 TO COPANO Y JCT-RLC	1.2
N	851267	COPANO E2 TO COPANO Y JCT-RLC	1.3
N	851266	NQ STA 4"-RLC	1.4
N	851265	REFUGIO EL OSO 4" RLC	1.5
N	851262	LAMBERT STA-RLC	1.7
N	851272	TCG 2 TIE IN-RHC	1.0
N	851260	REFUGIO STA. 6" RLC	3.0
N	851259	MELON 1 & 2 TO LAMBERT 8" RHC	2.1
N	851258	F JCT. RLC	4.6
N	851257	LAKE PASTURE 4" LOOP -RLC	12.8
N	851256	#4 TIE IN 6"-RLC	0.2
N	851264	GRETA 4"-RHC	1.6
N	851271	C PUMP RLC	1.0
N	851273	LAKE PASTURE 4" LOOP-RHC	1.0
N	851274	REFUGIO N & S TO CITATION ME O"CONNOR	0.9
N	851275	TCGI LEASE 4" RHC	0.9
N	851276	TCGI-RLC	0.9
N	851277	LENORE JOSIE TO GRETA 4" RHC	0.8

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N	851278	NQ COPANO D TO NQ "Y" RLC, 4"	0.8
N	851279	5800 #1 TO COPANO Y JCT-RLC	0.8
N	851280	CLAUDE HEARD RLC	0.7
N	851281	LAKE PASTURE 4" LOOP	0.6
N	851282	MAUDE A-RLC	0.6
N	851283	O'CONNOR C JCT. RLC, 4"	0.6
N	851255	O'CONNER GAS PLANT	0.3
N	752130	MIRANDO DUVAL MAINLINE 8"	38.0
N	851270	PENNZOIL C TO NQ - LAMBERT 10" RHC	1.2
N	851241	FANNIE HEARD	5.3
N	451173	SHAFT TO HEARNE STA.	21.3
N	451174	SHAFT TO GERDES	23.6
N	451175	CALDWELL 6"	4.3
N	451176	WEST POINT TO THREE WAY	3.0
N	451177	ZOCH LOOP 6"	8.4
N	451178	GERDES TO THREE WAY TRAP	32.3
N	451179	THREE WAY TRAP TO ROSANKY STATION	12.4
N	451180	ROSAKNY STATION TO NIXON	55.8
N	451181	NIXON TO PETTUS	45.9
N	752123	TIVOLI 3.5	4.5
N	752128	SUN FIELD STATION	1.4
N	851263	HWY 136 4"	1.6
N	851240	REFUGIO 8" RHC	7.1
N	851284	NQ STA. 4" RLC	0.6
N	851254	NQ STATION 6"	0.4
N	851242	LAKE PASTURE	0.8
N	851243	NEW QUINTANA PUMP STATION	0.8
N	851244	DEFENSE	10.0
N	851245	NQ STA 6	2.4

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N	851246	NQ STATION	1.5
N	851247	LAMBERT STA	1.0
N	851248	CLAUDE HEARDE	0.8
N	851249	LAMBERT PEN	0.7
N	851250	KOCH PL LP	0.6
N	851251	LAMBERT STATION	0.5
N	851252	RLC MAIN	0.4
N	851253	O'CONNOR A TO NQ "Y" RLC	0.4
N	851239	INGELSIDE 8" RHC	28.2
N	851337	#1 LEE WHEELER TO LA BILLING TO N. TILDEN, 3"	0.6
N	851322	SUN FIELD STATION	17.0
N	851323	MONTE CRISTO GATHERING	14.8
N	851324	SHELL-LOPEZ-4"	10.0
N	851327	THREE RIVERS 6"	16.8
N	851329	MIRANDO	27.3
N	851330	TILDEN STA.	6.1
N	851331	GRANT WILLIAMS (A)	3.8
N	851332	TILDEN 6", 4"	2.1
N	851333	WC RUTHERFORD 4"	1.2
N	851334	LA BILLINGS TO N. TILDEN	0.4
N	851321	GARCIA MAIN GATHERING 4"	19.5
N	851336	N. TILDEN GATHERING 3"	0.8
N	851326	YUTTERIA GATHERING	5.9
N	851338	N. WHEELER TO TILDEN 6"	0.5
N	851339	HO TAYLOR TO TILDEN 6"	0.9
N	851340	PONTIAC 8" PORTILLA LINE	10.0
N	851341	12" RLC TIE-IN	32.0
N	851342	TIVOLI 6"	11.4
N	851343	HEYSER STA 6"	5.4

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N	851344	HEYSER STA. 4"	4.0
N	851345	N. TILDEN GATHERING 4"	6.1
N	851261	MELON 1 & 2 TO LAMBERT 4" RHC	1.8
N	851285	ILAMBERT10 " RHC	0.6
N	851335	GRANT WILLIAMS A TO LA BILLINGS TO N. TILDEN	1.8
N	851295	COPANO NORDEN & MORRIS LATERAL RLC	0.3
N	851286	NQ LAMBERT 10"-RHC	0.6
N	851287	LAMBERT H&D O RHC	0.6
N	851288	FANNIE HEARD TO GRETA 4" RHC	0.5
N	851289	LAMBERT RHC	0.5
N	851290	B1 RLC	0.5
N	851291	H&D B JCT.-RLC	0.5
N	851292	REFUGIO 6"-RLC	0.4
N	851328	N. TILDEN 6"	0.9
N	851294	MAUDE A L/P RLC	0.4
N	851320	SUN FIELD STA.	1.0
N	851296	C PUMP	0.3
N	851297	JB HEARD 4" RHC	0.3
N	851298	GRETA 6"-RHC	0.1
N	851316	FALLS CITY STA.	1.8
N	851319	KELSEY 6"	11.0
N	851293	5800 T/I-RLC	0.4
N	851299	5800 #2 T/I RLC	0.1
N	851318	YUTTERIA 6"	21.0
N	851317	SEELIGSON STATION -8"	50.8
N	851315	WEIGANG GATHERING	1.0
N	851314	PETTUS 6"	13.6
N	851313	POWERS STA. 8"	39.1
N	851301	REFUGIO B1 TO CITATION ME O'CONNER	2.1

N	851300	REFUGIO STA.-RLC	5.5
R	750207	AGUA DULCE 10"	29.0
R	450937	STAR 8"	3.2
R	750199	LAMBERT 10" CRUDE PIPELINE	4.1
R	750194	VIOLA 16"	32.4
R	750202	PEARSALL-DILLEY 10"	76.8
R	750185	VIOLA CRUDE PIPELINE #1	24.5
R	750183	KRC 12"	4.0
R	750120	EAST WHITE POINT 10"	5.2
R	450938	MARLIN TO TEMPLE 4" (SOUTHWEST PIPELINE)	38.6
R	750196	CRUDE/RATTLESNAKE 10"-12"	542.9
R	750209	MAYO 10"	28.0
R	731687	KRC OXY HYDROGEN 6"/10" PIPELINE	2.6
R	752119	MAYO	62.1
R	752120	KRC 6" & 8" PROPYLENE/PROPANE	8.0
R	750213	VIOLA	1.0
R	750188	KRC BURNER CARGO	7.0
R	752118	THREE RIVERS	62.4
R	752117	LEOPARD #2	48.1
R	752116	REFUGIO 12" CRUDE PIPELINE	29.5
R	752114	CASO CARGO	7.0
R	752113	BENAVIDES #1 T/I 4"	3.9
R	751920	INGLESIDE JCT. 12"	28.0
R	751852	KRC EAST 10"	6.7
R	751675	KRC OXY PROPANE 4" PIPELINE	3.5
R	752115	8" LPG P/L	7.0
R	751771	KRC EAST 8"	5.0

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (133 detail records)

Sum

1783.5

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KOCH PL / LONGVIEW

reg	sysid	sysname	Sum Of Miles
N	351753	SNODDY GATHERING	5.3
N	351762	HARRIS-NORTON MAINLINE	7.5
N	351759	FISHER GATHERING	11.8
N	351758	RODDEN GATHERING	2.7
N	351756	ANDERSON GATHERING	4.4
N	351751	THRASHER GATHERING	2.1
N	351754	KEY CORNER GATHERING	3.3
N	351752	LACY-SNYDER GATHERING	3.6
N	351763	STINCHCOMB TRUNKLINE	3.5
N	851364	MIDDLE 1/3 BP, KOCH	9.3
N	351755	INGRAM GATHERING	3.7
N	351767	SMITH-EXXON 3"	0.1
N	851347	POWELL GATHERING	3.7
N	851348	MOBIL-SNODDY GATHERING	1.1
N	851361	GLADEWATER GATHERING	10.3
N	851363	MIDDLE 1/3	39.8
N	351749	MAINLINE	5.4
N	851365	MONDAY LEG	9.1
N	851366	NORTH 1/3 GATHERING	33.5
N	851367	LAKE DIVERNIA LEG	4.5
N	851368	SOUTH 1/3 BP, KOCH	4.9
N	851369	SOUTH 1/3	14.7
N	851362	MOBIL GATHERING	4.0
N	351750	ADD'L LATERALS OFF MAINLINE	3.8
Summary for 'ocname' = KOCH PL / LONGVIEW (24 detail records)			
Sum			192.1

KOCH PL / MEDFORD

reg	sysid	sysname	Sum Of Miles
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N	950009	STONEWALL (EAST HAMLIN)	31.6
N	950012	TRENT	20.8
N	851229	CRUDE/MUENSTER	31.2
N	950010	UPTON (OR BENEDUM)	11.3
N	950008	PARDUE	3.3
N	950007	DRIVER	3.5
N	950006	ACKERLEY (OR GOOD)	19.4
N	950005	QUITO (OR HENDRICKS)	57.7
N	950004	MCELROY (OR AMACKER)	112.0
N	950003	HASKELL	333.7
N	851226	GAINESVILLE, SHERMAN LEG	27.8
N	950002	BRECKENRIDGE	75.0
N	950001	GAINESVILLE	356.0
N	551956	NEEDERLAND 8"	64.0
N	950011	GARZA	15.7
R	650199	EP MIX/CHICO-FARMERSVILLE 4", 6"	92.6
R	651440	SOUTHLAKE 12"	12.0
R	651441	DFW 8"	8.1
R	752126	SOUR LAKE STA. 8"	11.0
R	752127	ARRIOLA STA NO. 2, 6"	0.5

Summary for 'ocname' = KOCH PL / MEDFORD (20 detail records)
Sum

1287.2

KOCH PL / MIDLAND

reg sysl sysname

Sum Of Miles

N	851231	QUITO CRUDE GATHERING	26.6
N	851220	ACKERLEY	14.4
N	851221	GARZA SYS.	63.0
N	851222	HASKELL (WEST LEG)	95.8
N	851223	PARDUE	12.5
N	851224	STONEWALL GATH. SYSTEM	34.6

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N	851230	MCELROY GATHERING	23.0
N	851232	DRIVER GATHERING	39.0
N	851233	UPTON CRUDE GATHERING	8.0
N	851225	TRENT	19.4

Summary for 'ocname' = KOCH PL / MIDLAND (10 detail records)

Sum	336.3
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Summary for 'opname' = KOCH PIPELINE CO., L.P. (188 detail records)

Sum	3631.5
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KOCH REFINING COMPANY, L.P.

KOCH REF. LP / CORPUS CHRISTI

req	sysid	sysname	Sum Of Miles
R	751982	TPL #2 CORPUS TO GONZALES	136.0
R	451137	TP1-SAN ANTONIO TO AUSTIN	95.0
R	451139	TPL #2-GONZALES TO WACO	141.0
R	451141	TP1-AUSTIN TO WACO	110.0
R	652087	TP11-WACO TO EULESS	106.0
R	751981	TP1-CORPUS TO SAN ANTONIO	134.5
Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (6 detail records)			
Sum			722.5
Summary for 'opname' = KOCH REFINING COMPANY, L.P. (6 detail records)			
Sum			722.5
Summary for 'jurisdiction' = Intrastate (195 detail records)			
Sum			4525.9
Grand Total			6835.9

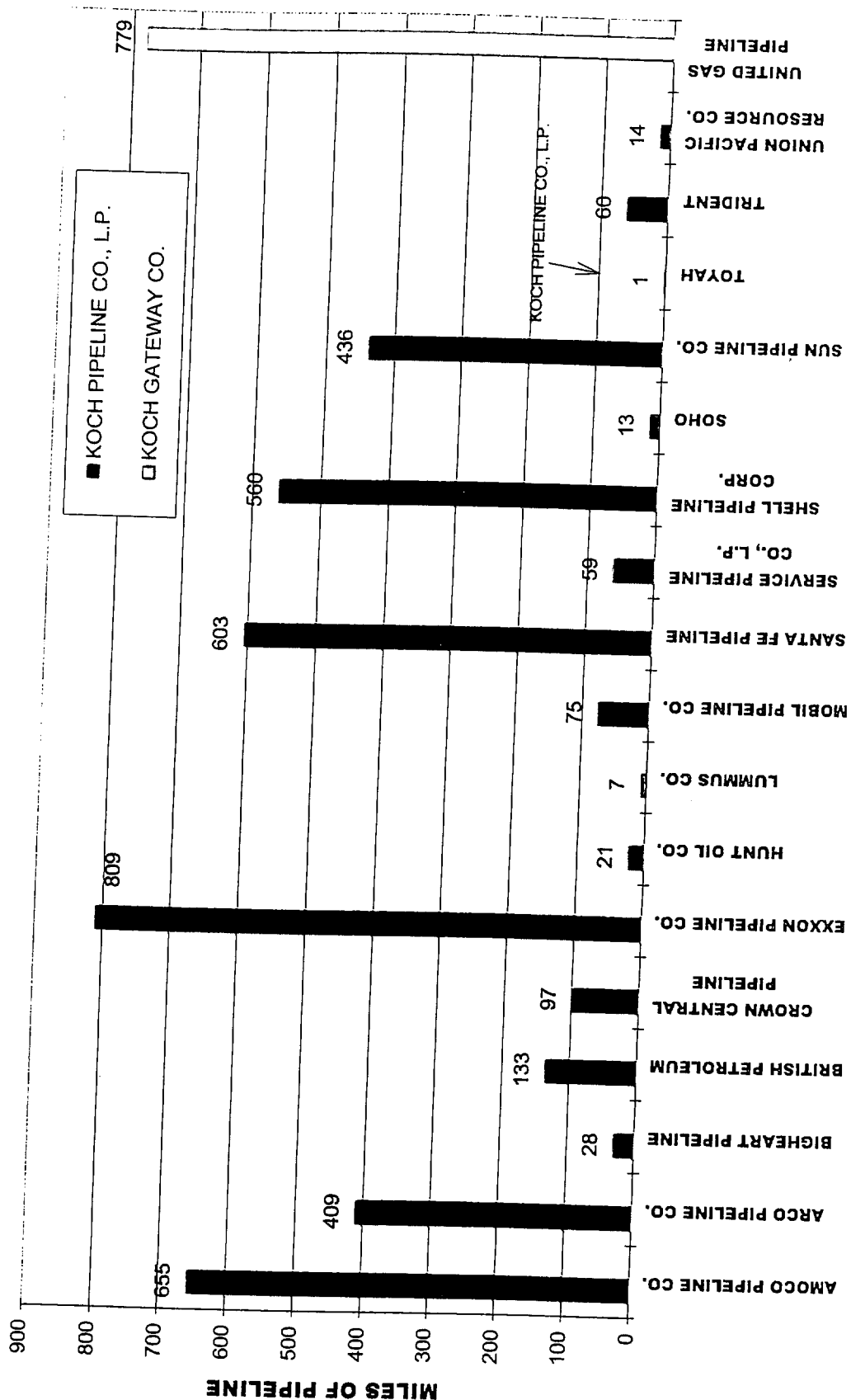
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RRCII 02240

Previous Operators of Pipeline Inspected

RRCH 02241

PREVIOUS OPERATORS



RRCII 02242

Miles of Pipe by Previous Operator

AMOCO PIPELINE COMPANY

KOCH PIPELINE CO., L.P.

KOCH PL / LONGVIEW

sysid	sysname	P/I	date_P/I	Sum Of Miles
851363	MIDDLE 1/3	P	1/1/68	39.8
351763	STINCHCOMB TRUNKLINE	P	1/1/68	3.5
851365	MONDAY LEG	P	1/1/68	9.1
851367	LAKE DIVERNIA LEG	P	1/1/68	4.5
851361	GLADEWATER GATHERING	P	1/1/68	10.3
351754	KEY CORNER GATHERING	P	1/1/68	3.3
351753	SNODDY GATHERING	P	1/1/68	5.3
351752	LACY-SNYDER GATHERING	P	1/1/68	3.6
351751	THRASHER GATHERING	P	1/1/68	2.1
351750	ADD'L LATERALS OFF MAINLINE	P	1/1/68	3.8
351749	MAINLINE	P	1/1/68	5.4
Summary for 'ocname' = KOCH PL / LONGVIEW (11 detail records)				90.7
Sum				

KOCH PL / MEDFORD

sysid	sysname	P/I	date_P/I	Sum Of Miles
950003	HASKELL	P		234.8
950004	MCELROY (OR AMACKER)	P	1/1/67	85.0
950003	HASKELL	P	1/1/67	98.9
950002	BRECKENRIDGE	P	1/1/67	75.0
950005	QUITO (OR HENDRICKS)	P	1/1/67	47.0
Summary for 'ocname' = KOCH PL / MEDFORD (5 detail records)				540.7
Sum				

KOCH PL / MIDLAND

sysid	sysname	P/I	date_P/I	Sum Of Miles
851222	HASKELL (WEST LEG)	P	1/1/69	23.6

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Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)	
Sum	23.6
Summary for 'opname' = KOCH PIPELINE CO., L.P. (17 detail records)	
Sum	655.0
Summary for 'prev_oper' = AMOCO PIPELINE COMPANY (17 detail records)	
Sum	655.0

ARCO PIPE LINE COMPANY**KOCH PIPELINE CO., L.P.****KOCH PL / MEDFORD**

sysid	sysname	P/I	date_P/I	Sum Of Miles
950001	GAINESVILLE	P		328.0
752126	SOUR LAKE STA. 8"	P	1/1/55	11.0
752127	ARRIOLA STA NO. 2, 6"	P	1/1/78	0.5
851229	CRUDE/MUENSTER	P	4/1/95	31.2
851228	GAINESVILLE, NOCONA LEG	P	4/1/95	2.0
851226	GAINESVILLE, SHERMAN LEG	P	4/1/95	27.8
851227	GAINESVILLE, BEST DISCH.	P	4/1/95	9.4

Summary for 'ocname' = KOCH PL / MEDFORD (7 detail records)	
Sum	409.9
Summary for 'opname' = KOCH PIPELINE CO., L.P. (7 detail records)	
Sum	409.9
Summary for 'prev_oper' = ARCO PIPE LINE COMPANY (7 detail records)	
Sum	409.9

BIGHEART PPIPELINE**KOCH PIPELINE CO., L.P.****KOCH PL / MEDFORD**

sysid	sysname	P/I	date_P/I	Sum Of Miles
950001	GAINESVILLE	P	1/1/87	28.0

Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)	
Sum	28.0
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)	
Sum	28.0
Summary for 'prev_oper' = BIGHEART PPIPELINE (1 detail record)	
Sum	28.0

BRITISH PETROLEUM

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KOCH PIPELINE CO., L.P.**KOCH PL / LONGIVEW**

sysid	sysname	P/I	date_P/I	Sum Of Miles
851369	SOUTH 1/3	P	1/1/91	14.7
851364	MIDDLE 1/3 BP, KOCH	P	1/1/91	9.3
851366	NORTH 1/3 GATHERING	p	1/1/91	33.5
851368	SOUTH 1/3 BP, KOCH	P	1/1/91	4.9
351762	HARRIS-NORTON MAINLINE	P	1/1/91	7.5
Summary for 'ocname' = KOCH PL / LONGIVEW (5 detail records)				
Sum				69.9

KOCH PL / MEDFORD

sysid	sysname	P/I	date_P/I	Sum Of Miles
551956	NEEDERLAND 8"	P	1/1/90	64.0
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				
Sum				64.0
Summary for 'opname' = KOCH PIPELINE CO., L.P. (6 detail records)				
Sum				133.9
Summary for 'prev_oper' = BRITISH PETROLEUM (6 detail records)				
Sum				133.9

CROWN CENTRAL PIPELINE**KOCH PIPELINE CO., L.P.****KOCH PL / MEDFORD**

sysid	sysname	P/I	date_P/I	Sum Of Miles
950006	ACKERLEY (OR GOOD)	P		19.2
950004	MCELROY (OR AMACKER)	P		27.0
950005	QUITO (OR HENDRICKS)	P		10.7
Summary for 'ocname' = KOCH PL / MEDFORD (3 detail records)				
Sum				56.9

KOCH PL / MIDLAND

sysid	sysname	P/I	date_P/I	Sum Of Miles
851220	ACKERLEY	P	1/25/88	14.4
851231	QUITO CRUDE GATHERING	P	1/25/88	26.6

Summary for 'ocname' = KOCH PL / MIDLAND (2 detail records)
 Sum 41.0
 Summary for 'opname' = KOCH PIPELINE CO., L.P. (5 detail records)
 Sum 97.9
 Summary for 'prev_oper' = CROWN CENTRAL PIPELINE (5 detail records)
 Sum 97.9

EXXON PIPELINE COMPANY

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	P/I	date_P/I	Sum Of Miles
752115	8" LPG P/L	P	1/1/81	7.0
752116	REFUGIO 12" CRUDE PIPELINE	P	1/1/94	29.5
750199	LAMBERT 10" CRUDE PIPELINE	P	1/1/94	4.1
851265	REFUGIO EL OSO 4" RLC	P	1/1/95	1.5
851264	GRETA 4"-RHC	P	1/1/95	1.6
851266	NQ STA 4"-RLC	P	1/1/95	1.4
851290	B1 RLC	P	1/1/95	0.5
851285	ILAMBERT10 " RHC	P	1/1/95	0.6
851263	HWY 136 4"	P	1/1/95	1.6
851267	COPANO E2 TO COPANO Y JCT-RLC	P	1/1/95	1.3
851288	FANNIE HEARD TO GRETA 4" RHC	P	1/1/95	0.5
851287	LAMBERT H&D O RHC	P	1/1/95	0.6
851268	COPANO B1 & E3 TO COPANO Y JCT-RLC	P	1/1/95	1.2
851269	LAMBERT C INJECTION TO LAMBERT 10" RHC	P	1/1/95	1.2
851270	PENNZOIL C TO NQ - LAMBERT 10" RHC	P	1/1/95	1.2
851292	REFUGIO 6"-RLC	P	1/1/95	0.4
851262	LAMBERT STA-RLC	P	1/1/95	1.7
851279	5800 #1 TO COPANO Y JCT-RLC	P	1/1/95	0.8
851278	NQ COPANO D TO NQ "Y" RLC, 4"	P	1/1/95	0.8
851277	LENORE JOSIE TO GRETA 4" RHC	P	1/1/95	0.8
851280	CLAUDE HEARD RLC	P	1/1/95	0.7
851281	LAKE PASTURE 4" LOOP	P	1/1/95	0.6

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851286	NQ LAMBERT 10"-RHC	P	1/1/95	0.6
851283	O'CONNOR C JCT. RLC, 4"	P	1/1/95	0.6
851271	C PUMP RLC	P	1/1/95	1.0
851284	NQ STA. 4" RLC	P	1/1/95	0.6
851275	TCGI LEASE 4" RHC	P	1/1/95	0.9
851276	TCGI-RLC	P	1/1/95	0.9
851274	REFUGIO N & S TO CITATION ME O'CONNOR	P	1/1/95	0.9
851273	LAKE PASTURE 4" LOOP-RHC	P	1/1/95	1.0
851272	TCG 2 TIE IN-RHC	P	1/1/95	1.0
851282	MAUDE A-RLC	P	1/1/95	0.6
851248	CLAUDE HEARDE	P	1/1/95	0.8
750185	VIOLA CRUDE PIPELINE #1	P	1/1/95	24.5
750196	CRUDE/RATTLESNAKE 10"-12"	P	1/1/95	542.9
750213	VIOLA	P	1/1/95	1.0
751852	KRC EAST 10"	P	1/1/95	6.7
751920	INGLESIDE JCT. 12"	P	1/1/95	28.0
752113	BENAVIDES #1 T/I 4"	P	1/1/95	3.9
752117	LEOPARD #2	P	1/1/95	48.1
851239	INGELSIDE 8" RHC	P	1/1/95	28.2
851240	REFUGIO 8" RHC	P	1/1/95	7.1
851241	FANNIE HEARD	P	1/1/95	5.3
851242	LAKE PASTURE	P	1/1/95	0.8
851243	NEW QUINTANA PUMP STATION	P	1/1/95	0.8
851245	NQ STA 6	P	1/1/95	2.4
851250	KOCH PL LP	P	1/1/95	0.6
851253	O'CONNOR A TO NQ "Y" RLC	P	1/1/95	0.4
851260	REFUGIO STA. 6" RLC	P	1/1/95	3.0
851259	MELON 1 & 2 TO LAMBERT 8" RHC	P	1/1/95	2.1
851258	F JCT. RLC	P	1/1/95	4.6
851257	LAKE PASTURE 4" LOOP -RLC	P	1/1/95	12.8

851256	#4 TIE IN 6"-RLC	P	1/1/95	0.2
851246	NQ STATION	P	1/1/95	1.5
851254	NQ STATION 6"	P	1/1/95	0.4
851247	LAMBERT STA	P	1/1/95	1.0
851252	RLC MAIN	P	1/1/95	0.4
851251	LAMBERT STATION	P	1/1/95	0.5
851293	5800 T/I-RLC	P	1/1/95	0.4
851249	LAMBERT PEN	P	1/1/95	0.7
851291	H&D B JCT.-RLC	P	1/1/95	0.5
851261	MELON 1 & 2 TO LAMBERT 4" RHC	P	1/1/95	1.8
851255	O'CONNER GAS PLANT	P	1/1/95	0.3
851289	LAMBERT RHC	P	1/1/95	0.5
851294	MAUDE A L/P RLC	P	1/1/95	0.4
851301	REFUGIO B1 TO CITATION ME O'CONNER	P	1/1/95	2.1
851300	REFUGIO STA.-RLC	P	1/1/95	5.5
851299	5800 #2 T/I RLC	P	1/1/95	0.1
851298	GRETA 6"-RHC	P	1/1/95	0.1
851295	COPANO NORDEN & MORRIS LATERAL RLC	P	1/1/95	0.3
851297	JB HEARD 4" RHC	P	1/1/95	0.3
851296	C PUMP	P	1/1/95	0.3

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (72 detail records)

Sum 809.2

Summary for 'opname' = KOCH PIPELINE CO., L.P. (72 detail records)

Sum 809.2

Summary for 'prev_oper' = EXXON PIPELINE COMPANY (72 detail records)

Sum 809.2

HUNT OIL COMPANY

KOCH PIPELINE CO., L.P.

KOCH PL / MIDLAND

sysid	sysname	P/I	date_P/I	Sum of Miles
851230	MCELROY GATHERING	P	1/1/81	21.3

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Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)	21.3
Sum	
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)	21.3
Sum	
Summary for 'prev_oper' = HUNT OIL COMPANY (1 detail record)	21.3
Sum	

LUMMUS COMPANY**KOCH PIPELINE CO., L.P.****KOCH PL / CORPUS CHRISTI**

sysid	sysname	P/I	date_P/I	Sum Of Miles
752114	CASO CARGO	P	1/1/52	7.0
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)				7.0
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)				7.0
Sum				
Summary for 'prev_oper' = LUMMUS COMPANY (1 detail record)				7.0
Sum				

MOBIL PIPE LINE CO.**KOCH PIPELINE CO., L.P.****KOCH PL / CORPUS CHRISTI**

sysid	sysname	P/I	date_P/I	Sum Of Miles
752120	KRC 6" & 8" PROPYLENE/PROPANE	P	1/1/86	2.0
851337	#1 LEE WHEELER TO LA BILLING TO N. TILDEN, 3"	P	1/1/87	0.6
851345	N. TILDEN GATHERING 4"	P	1/1/87	6.1
851336	N. TILDEN GATHERING 3"	P	1/1/87	0.8
851330	TILDEN STA.	P	1/1/87	6.1
851339	HO TAYLOR TO TILDEN 6"	P	1/1/87	0.9
851334	LA BILLINGS TO N. TILDEN	P	1/1/87	0.4
851333	WC RUTHERFORD 4"	P	1/1/87	1.2
851332	TILDEN 6", 4"	P	1/1/87	2.1
851327	THREE RIVERS 6"	P	1/1/87	16.8
851328	N. TILDEN 6"	P	1/1/87	0.9
851331	GRANT WILLIAMS (A)	P	1/1/87	3.8

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851335	GRANT WILLIAMS A TO LA BILLINGS TO N. TILDEN	P	1/1/87	1.8
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (13 detail records)				43.6
Sum				

KOCH PL / LONGVIEW

sysid	sysname	P/I	date_P/I	Sum Of Miles
351759	FISHER GATHERING	P	1/1/96	11.8
851348	MOBIL-SNODDY GATHERING	P	1/1/96	1.1
851362	MOBIL GATHERING	P	1/1/96	4.0
351758	RODDEN GATHERING	P	1/1/96	2.7
851347	POWELL GATHERING	P	1/1/96	3.7
351756	ANDERSON GATHERING	P	1/1/96	4.4
351755	INGRAM GATHERING	P	1/1/96	3.7
Summary for 'ocname' = KOCH PL / LONGVIEW (7 detail records)				31.4
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (20 detail records)				75.0
Sum				
Summary for 'prev_oper' = MOBIL PIPE LINE CO. (20 detail records)				75.0
Sum				

SANTA FE PIPELINE

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	P/I	date_P/I	Sum Of Miles
450938	MARLIN TO TEMPLE 4" (SOUTHWEST PIPELINE)	P	1/1/84	38.6
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)				38.6
Sum				

KOCH PL / MIDLAND

sysid	sysname	P/I	date_P/I	Sum Of Miles
851346	CHAPARRAL PIPELINE	P	1/1/88	565.1
Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)				565.1
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)				603.7
Sum				
Summary for 'prev_oper' = SANTA FE PIPELINE (2 detail records)				603.7
Sum				

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SERVICE PIPELINE CO.**KOCH PIPELINE CO., L.P.****KOCH PL / MEDFORD**

sysid	sysname	P/I	date_P/I	Sum Of Miles
851228	GAINESVILLE, NOCONA LEG	P	1/1/65	17.6
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				17.6
Sum				

KOCH PL / MIDLAND

sysid	sysname	P/I	date_P/I	Sum Of Miles
851222	HASKELL (WEST LEG)	P	1/1/69	42.3
Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)				42.3
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)				59.9
Sum				
Summary for 'prev_oper' = SERVICE PIPELINE CO. (2 detail records)				59.9
Sum				

SHELL PIPE LINE CORP.**KOCH PIPELINE CO., L.P.****KOCH PL / MEDFORD**

sysid	sysname	P/I	date_P/I	Sum Of Miles
950007	DRIVER	P	10/1/92	3.5
950008	PARDUE	P	10/1/92	3.3
950009	STONEWALL (EAST HAMLIN)	P	10/1/92	31.6
950011	GARZA	P	10/1/92	15.7
950012	TRENT	P	10/1/92	20.8
851359	MCCAMEY	P	10/1/92	317.3
950010	UPTON (OR BENEDUM)	P	10/1/92	11.3
Summary for 'ocname' = KOCH PL / MEDFORD (7 detail records)				403.5
Sum				

KOCH PL / MIDLAND

sysid	sysname	P/I	date_P/I	Sum Of Miles
851224	STONEWALL GATH. SYSTEM	P	10/1/92	34.6

851221	GARZA SYS.	P	10/1/92	63.0
851233	UPTON CRUDE GATHERING	P	10/1/92	8.0
851232	DRIVER GATHERING	P	10/1/92	39.0
851223	PARDUE	P	10/1/97	12.5
Summary for 'ocname' = KOCH PL / MIDLAND (5 detail records)				
Sum				157.1
Summary for 'opname' = KOCH PIPELINE CO., L.P. (12 detail records)				
Sum				560.6
Summary for 'prev_oper' = SHELL PIPE LINE CORP. (12 detail records)				
Sum				560.6

SOHIO**KOCH PIPELINE CO., L.P.****KOCH PL / MIDLAND**

sysid	sysname	P/I	date_P/I	Sum Of Miles
851225	TRENT	P	1/1/90	13.4
Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)				
Sum				13.4
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)				
Sum				13.4
Summary for 'prev_oper' = SOHIO (1 detail record)				
Sum				13.4

SUN PIPE LINE COMPANY**KOCH PIPELINE CO., L.P.****HAZARDOUS LIQUID SYSTEMS/CORPUS**

sysid	sysname	P/I	date_P/I	Sum Of Miles
752125	FALLS CITY STATION TO PETTUS 6"	P	1/1/81	32.3
Summary for 'ocname' = HAZARDOUS LIQUID SYSTEMS/CORPUS (1 detail record)				
Sum				32.3

KOCH PL / CORPUS CHRISTI

sysid	sysname	P/I	date_P/I	Sum Of Miles
851344	HEYSEY STA. 4"	P	1/1/81	4.0
851313	POWERS STA. 8"	P	1/1/81	39.1
750120	EAST WHITE POINT 10"	P	1/1/81	5.2
851319	KELSEY 6"	P	1/1/81	11.0

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851315	WEIGANG GATHERING	P	1/1/81	1.0
851316	FALLS CITY STA.	P	1/1/81	1.8
851317	SEELIGSON STATION -8"	P	1/1/81	50.8
851318	YUTTERIA 6"	P	1/1/81	21.0
752120	KRC 6" & 8" PROPYLENE/PROPANE	P	1/1/81	6.0
752123	TIVOLI 3.5	P	1/1/81	4.5
851338	N. WHEELER TO TILDEN 6"	P	1/1/81	0.5
851329	MIRANDO	P	1/1/81	27.3
851326	YUTTERIA GATHERING	P	1/1/81	5.9
851324	SHELL-LOPEZ-4"	P	1/1/81	10.0
851343	HEYSER STA 6"	P	1/1/81	5.4
851244	DEFENSE	P	1/1/81	10.0
851323	MONTE CRISTO GATHERING	P	1/1/81	14.8
851322	SUN FIELD STATION	P	1/1/81	17.0
851321	GARCIA MAIN GATHERING 4"	P	1/1/81	19.5
851320	SUN FIELD STA.	P	1/1/81	1.0
752130	MIRANDO DUVAL MAINLINE 8"	P	1/1/81	38.0
752128	SUN FIELD STATION	P	1/1/81	1.4
851342	TIVOLI 6"	P	11/1/81	11.4
750207	AGUA DULCE 10"	P	11/1/81	29.0
751771	KRC EAST 8"	P	11/1/81	1.0
750209	MAYO 10"	P	1/1/85	28.0
750188	KRC BURNER CARGO	P	1/1/85	7.0
750194	VIOLA 16"	P	1/1/90	32.4

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (28 detail records)

Sum 403.8

Summary for 'opname' = KOCH PIPELINE CO., L.P. (29 detail records)

Sum 436.1

Summary for 'prev_oper' = SUN PIPE LINE COMPANY (29 detail records)

Sum 436.1

TOYAH

KOCH PIPELINE CO., L.P.

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KOCH PL / CORPUS CHRISTI

sysid	sysname	P/I	date_P/I	Sum Of Miles
731687	KRC OXY HYDROGEN 6"/10" PIPELINE	P	1/1/92	0.7
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)				0.7
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)				0.7
Sum				
Summary for 'prev_oper' = TOYAH (1 detail record)				0.7
Sum				

TRIDENT

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

sysid	sysname	P/I	date_P/I	Sum Of Miles
851360	TEXAS FERC	P	1/1/65	12.0
851360	TEXAS FERC	P	1/1/91	48.0
Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				60.0
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)				60.0
Sum				
Summary for 'prev_oper' = TRIDENT (2 detail records)				60.0
Sum				

UNION PACIFIC RESOURCE CO.

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	P/I	date_P/I	Sum Of Miles
851340	PONTIAC 8" PORTILLA LINE	P	11/1/96	10.0
751771	KRC EAST 8"	P	11/1/96	4.0
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (2 detail records)				14.0
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)				14.0
Sum				
Summary for 'prev_oper' = UNION PACIFIC RESOURCE CO. (2 detail records)				14.0
Sum				

UNITED GAS PIPE LINE

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	P/I	date_P/I	Sum Of Miles
831237	T-266 CARTHAGE TO STERLINGTON	P	1/1/45	17.0
831237	T-266 CARTHAGE TO STERLINGTON	P	1/1/81	0.2
831234	TPL-059 CARTHAGE	P	1/1/81	0.5
831234	TPL-059 CARTHAGE	P	1/1/92	112.5
831235	TPL-63 CARTHAGE	P	1/1/92	31.8
831236	TPL-92 CARTHAGE	P	1/1/92	4.2
831304	TPL-213 CARTHAGE	P	1/1/92	1.6
831302	TPL-264 CARTHAGE	P	1/1/92	0.2
831303	TPL-265 CARTHAGE	P	1/1/92	4.1
831310	TPL-65 CARTHAGE	P	1/1/92	1.8
831309	TPL 66-CARTHAGE	P	1/1/92	1.8
831308	TPL-86 CARTHAGE	P	1/1/92	1.3
831307	TPL-173 CARTHAGE	P	1/1/92	4.3
831306	TPL-212 CARTHAGE	P	1/1/92	6.9
831305	TPL-263 CARTHAGE	P	1/1/92	3.8
831238	391-02-01 CARTHAGE	P	1/1/92	24.5
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (16 detail records)				216.6
Sum				

KOCH GATEWAY/LONGVIEW

sysid	sysname	P/I	date_P/I	Sum Of Miles
831358	TPL-4-LONGVIEW	P	1/1/92	9.6
831349	TPL-391 LONGVIEW	P	1/1/92	21.3
831350	TPL-10 LONGVIEW	P	1/1/92	11.8
831351	TPL-65-2 LONGVIEW	P	1/1/92	18.8
831352	TPL-430 LONGVIEW	P	1/1/92	57.1
831353	TPL-11 LONGVIEW	P	1/1/92	121.9
831354	TPL-8 LONGVIEW	P	1/1/92	65.8
831355	TPL-178 LONGVIEW	P	1/1/92	0.1

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831357	TPL-6 LONGVIEW	P	1/1/92	4.3
831356	TPL-1 LONGVIEW	P	1/1/92	252.0
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (10 detail records)				
	Sum			562.8
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (26 detail records)				
	Sum			779.4
Summary for 'prev_oper' = UNITED GAS PIPE LINE (26 detail records)				
	Sum			779.4
Grand Total				4764.9

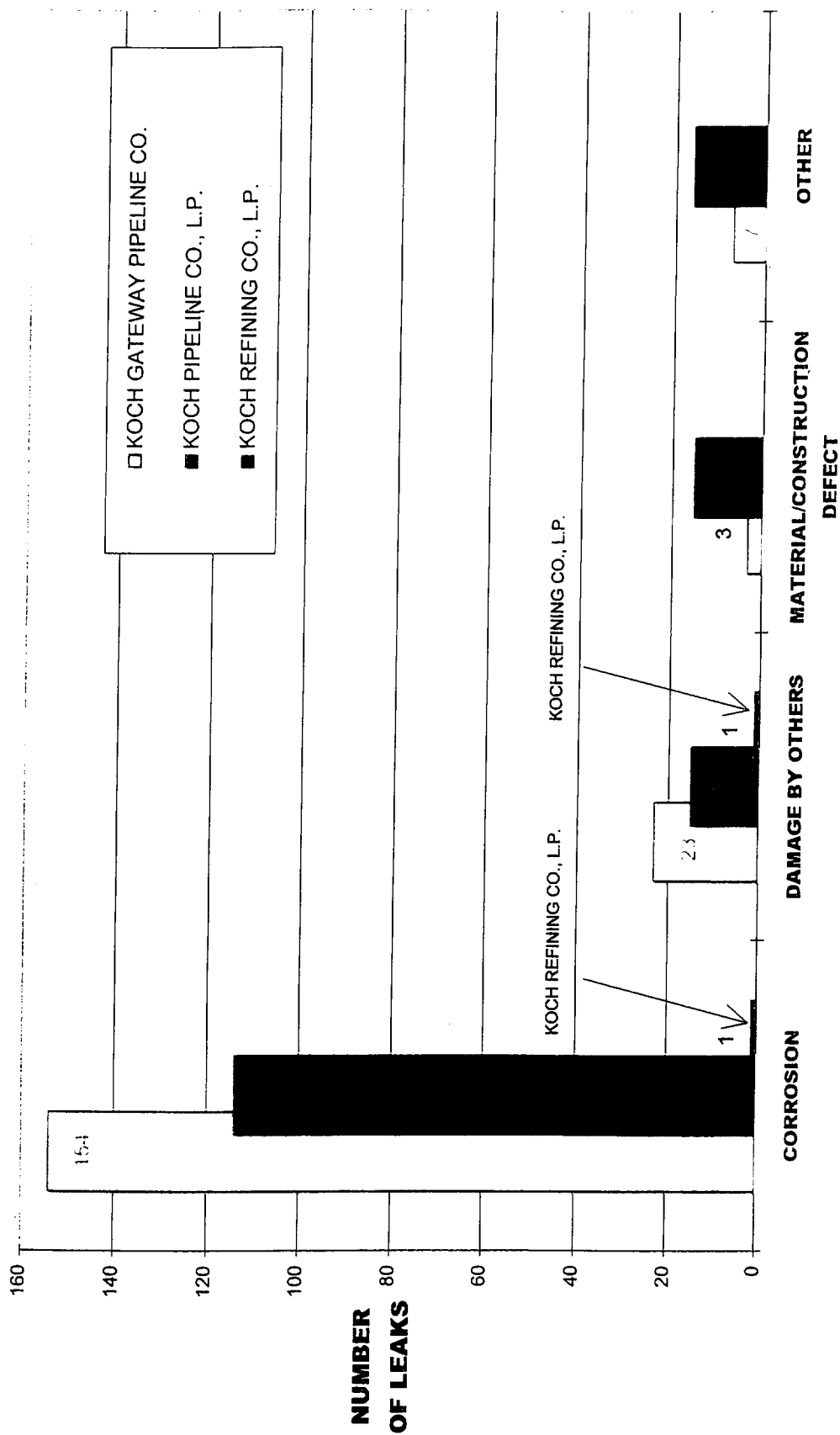
E

RRCII 02257

Leak History

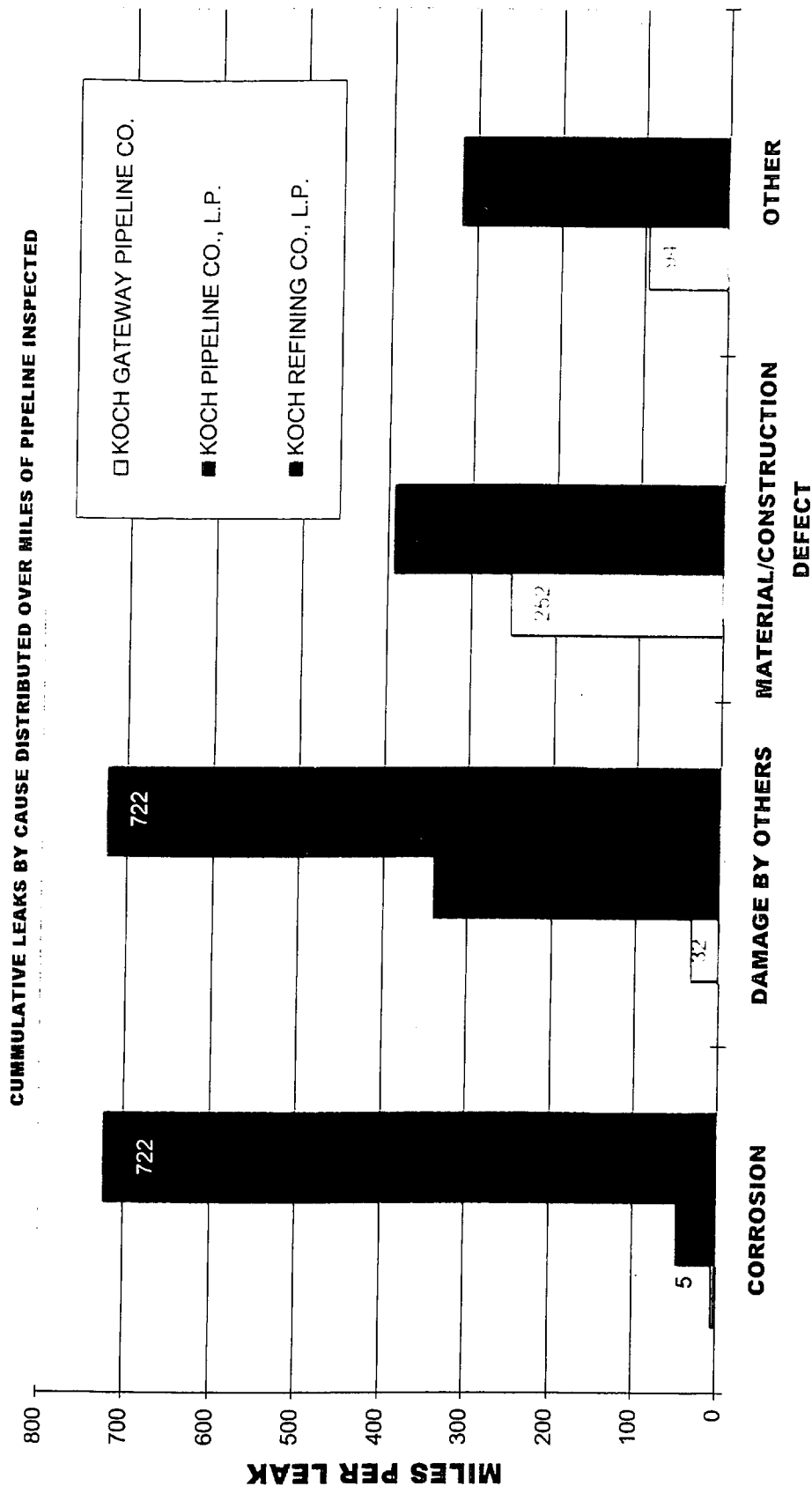
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LEAK SUMMARY LAST 10 YEARS



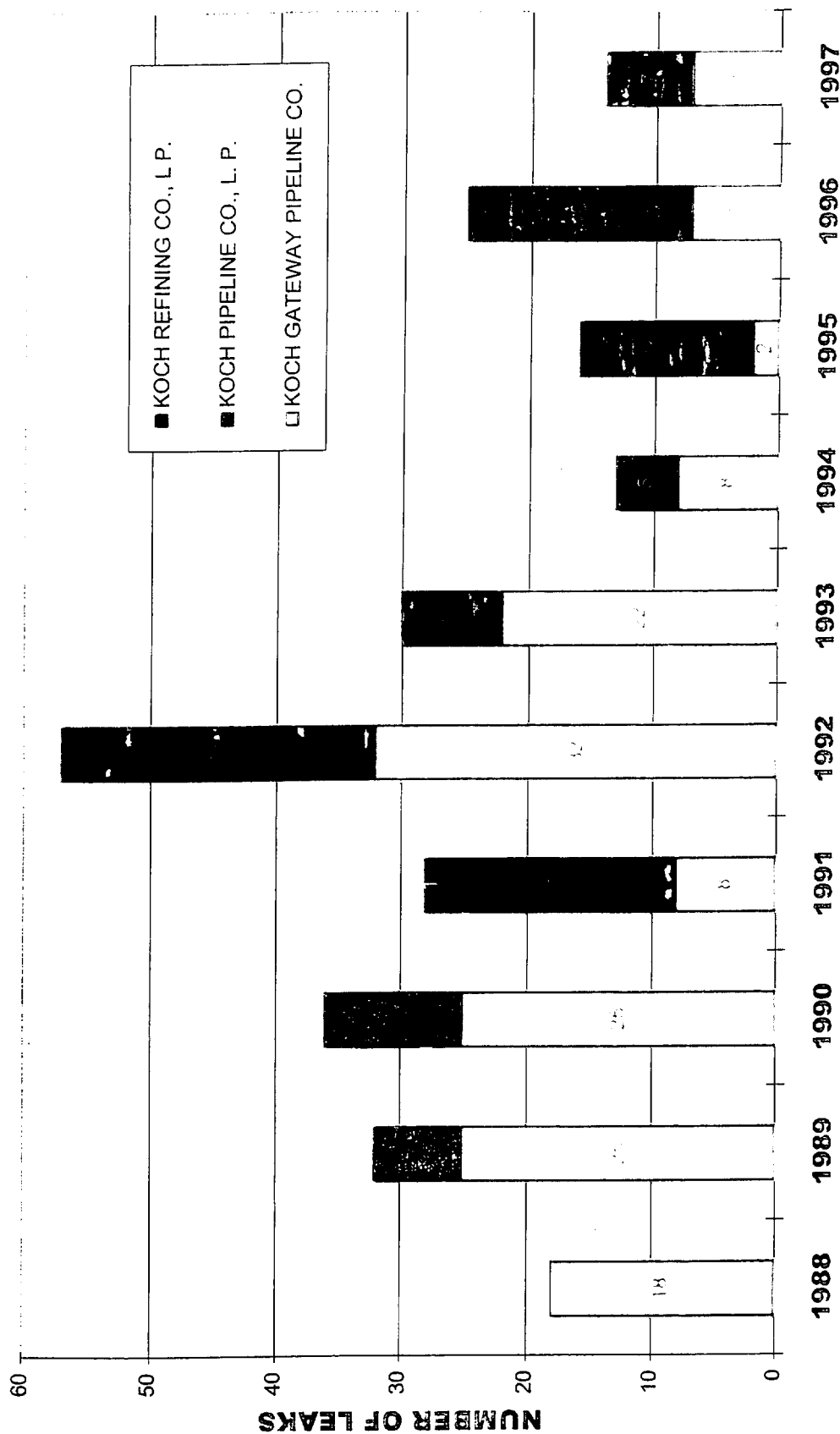
RRCII 02259

LEAK SUMMARY LAST 10 YEARS



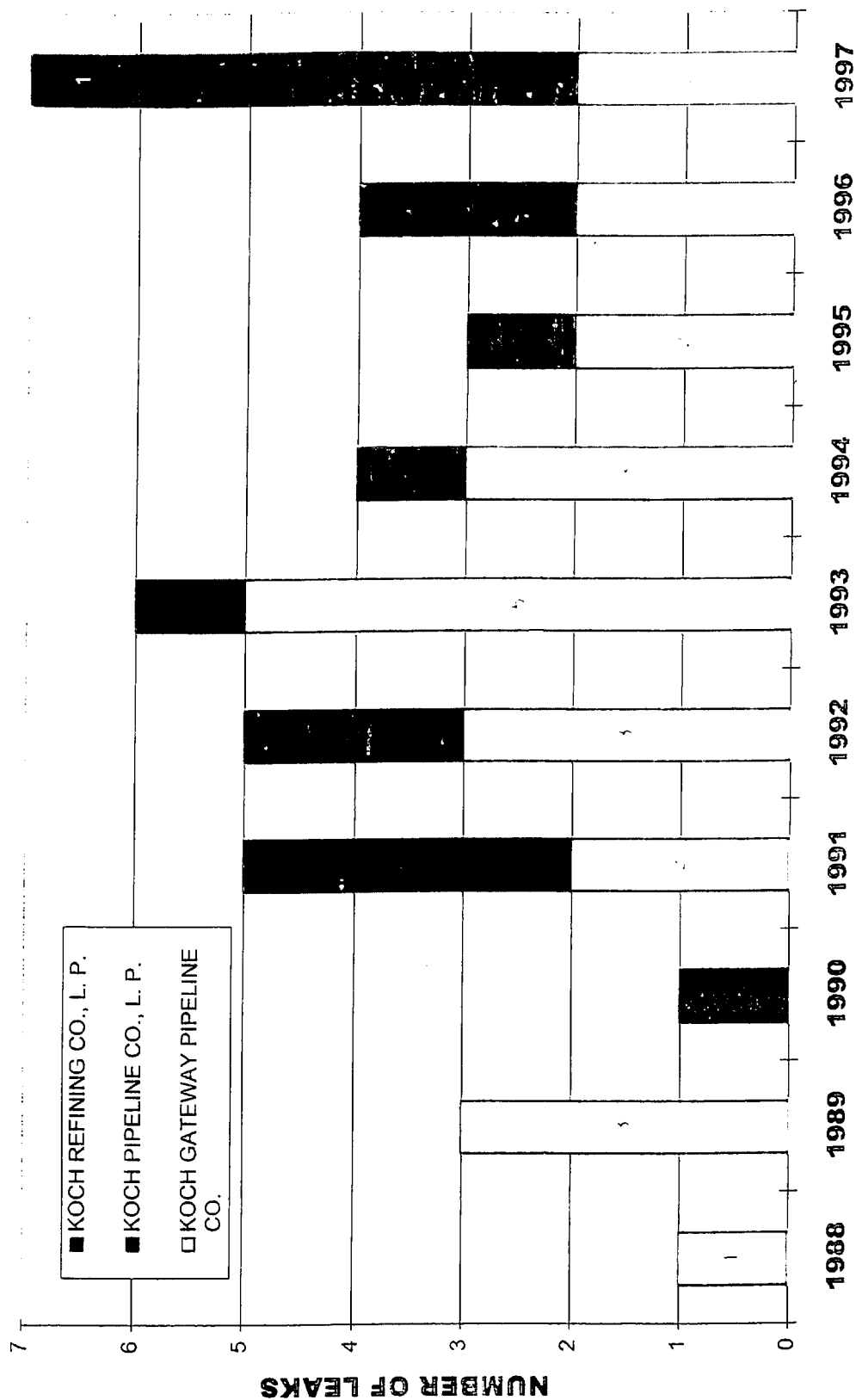
EXAMPLE: THE 1ST BAR GRAPH TO THE LEFT WOULD BE READ AS 1 LEAK OCCURRING EVERY 5 MILES OF PIPELINE INSPECTED

CORROSION



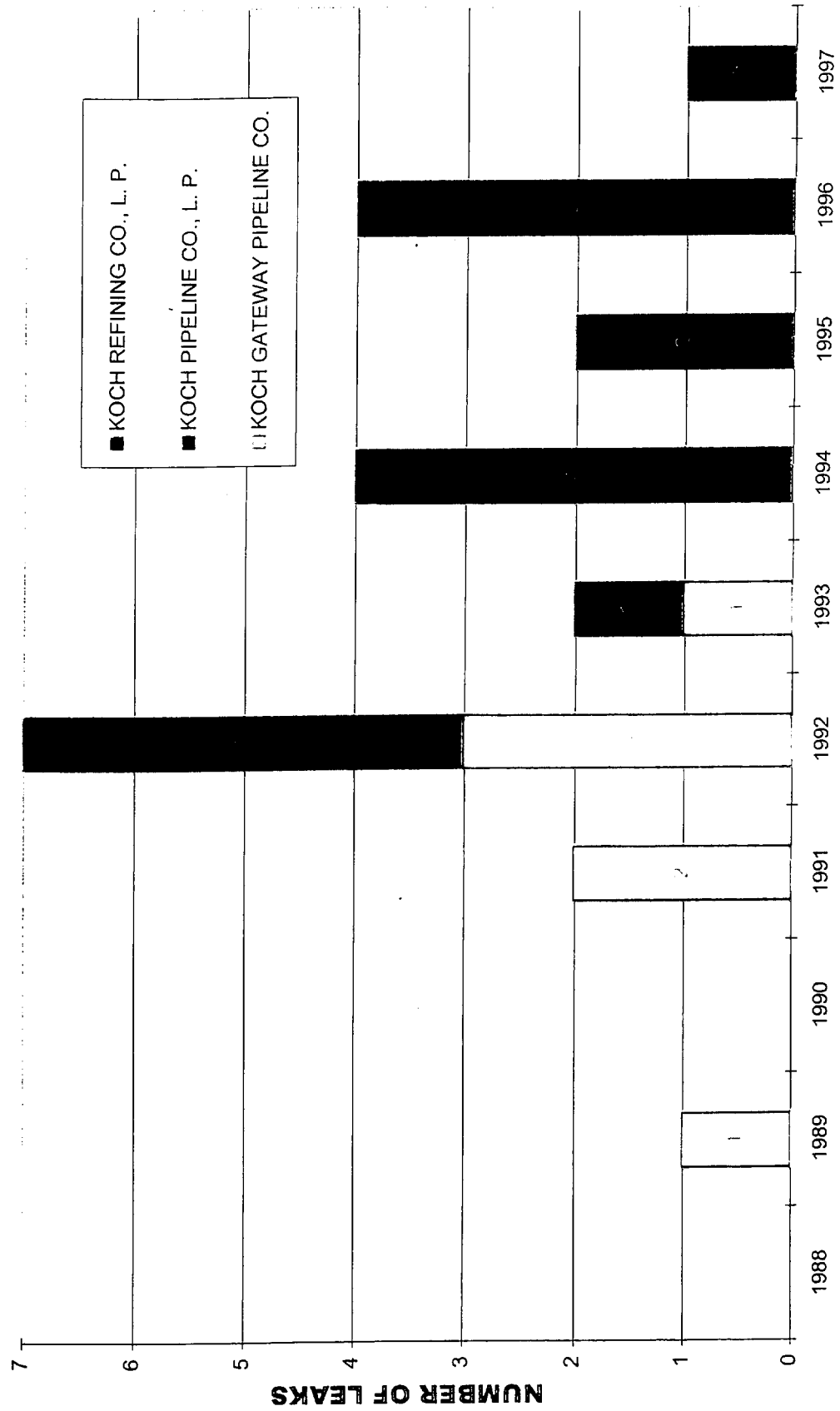
RRCII 02261

DAMAGE BY OTHERS



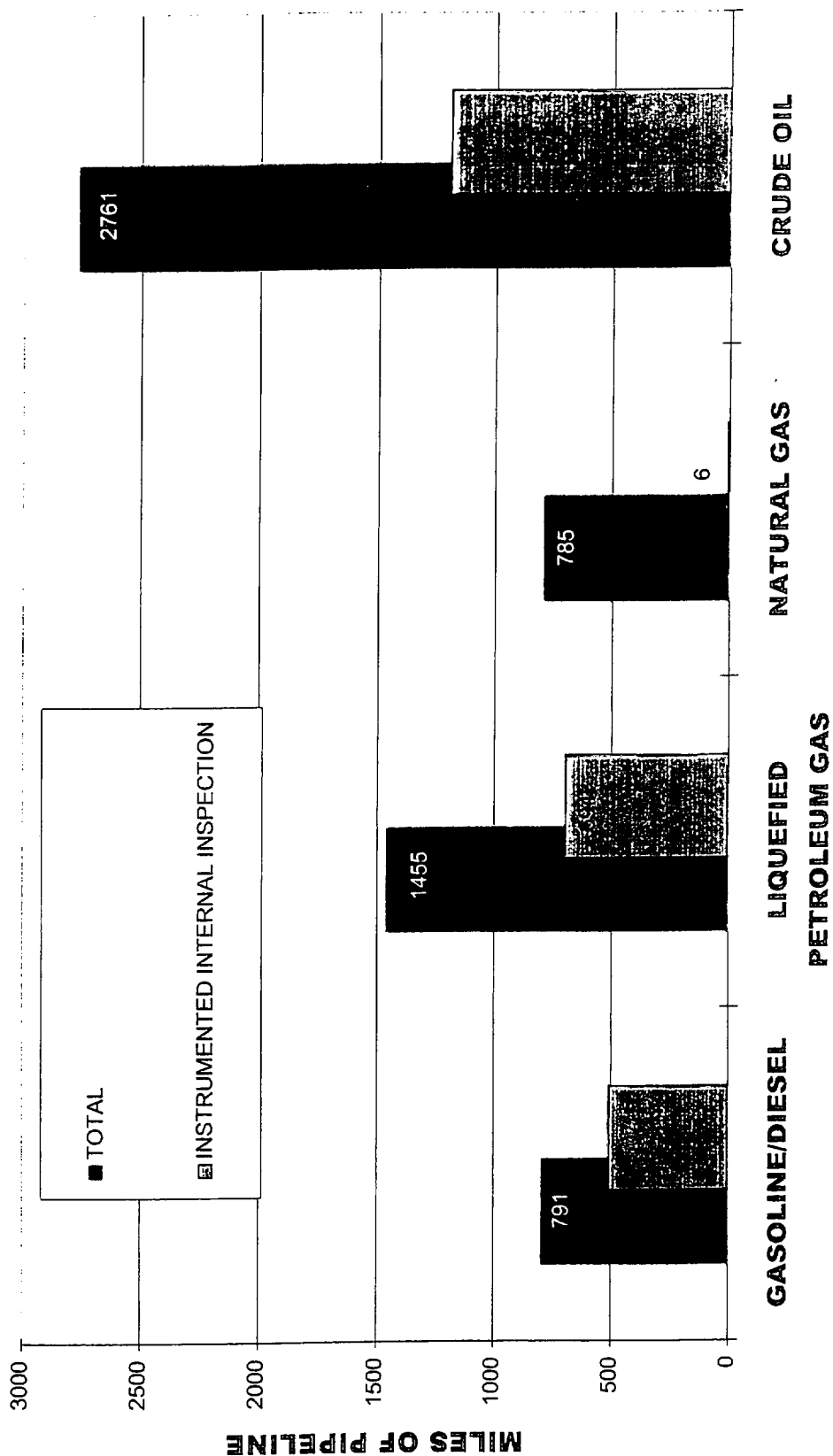
RRCII 02262

OTHER CAUSES



RRCII 02263

INSTRUMENTED INTERNAL INSPECTION



RRCII 02264

10 Year Leak History

CORROSION

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	Sum Of Leaks
831234	TPL-059 CARTHAGE	1
831234	TPL-059 CARTHAGE	1
831235	TPL-63 CARTHAGE	11
831235	TPL-63 CARTHAGE	1
831235	TPL-63 CARTHAGE	3
831235	TPL-63 CARTHAGE	4
831235	TPL-63 CARTHAGE	5
831235	TPL-63 CARTHAGE	1
831235	TPL-63 CARTHAGE	2
831235	TPL-63 CARTHAGE	3
831235	TPL-63 CARTHAGE	5
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (11 detail records)		37
Sum		

KOCH GATEWAY/LONGVIEW

sysid	sysname	Sum Of Leaks
831356	TPL-1 LONGVIEW	4
831356	TPL-1 LONGVIEW	3
831356	TPL-1 LONGVIEW	15
831356	TPL-1 LONGVIEW	16
831356	TPL-1 LONGVIEW	1
831356	TPL-1 LONGVIEW	8
831356	TPL-1 LONGVIEW	8
831356	TPL-1 LONGVIEW	9
831356	TPL-1 LONGVIEW	1

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831353	TPL-11 LONGVIEW	2
831353	TPL-11 LONGVIEW	6
831353	TPL-11 LONGVIEW	10
831353	TPL-11 LONGVIEW	2
831353	TPL-11 LONGVIEW	1
831353	TPL-11 LONGVIEW	4
831353	TPL-11 LONGVIEW	5
831353	TPL-11 LONGVIEW	12
831349	TPL-391 LONGVIEW	1
831349	TPL-391 LONGVIEW	1
831349	TPL-391 LONGVIEW	1
831349	TPL-391 LONGVIEW	1
831358	TPL-4-LONGVIEW	1
831358	TPL-4-LONGVIEW	1
831351	TPL-65-2 LONGVIEW	1
831354	TPL-8 LONGVIEW	1
831354	TPL-8 LONGVIEW	2
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (26 detail records)		117
Sum		
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (37 detail records)		154
Sum		

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Looks
851341	12" RLC TIE-IN	6
851341	12" RLC TIE-IN	3
851341	12" RLC TIE-IN	6
851341	12" RLC TIE-IN	6
851290	B1 RLC	1
851248	CLAUDE HEARDE	1
851268	COPANO B1 & E3 TO COPANO Y JCT-RLC	1

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750196	CRUDE/RATTLESNAKE 10"-12"	2
750196	CRUDE/RATTLESNAKE 10"-12"	1
851321	GARCIA MAIN GATHERING 4"	2
851321	GARCIA MAIN GATHERING 4"	2
851321	GARCIA MAIN GATHERING 4"	3
451178	GERDES TO THREE WAY TRAP	1
851343	HEYSER STA 6"	1
851343	HEYSER STA 6"	2
851343	HEYSER STA 6"	2
851239	INGELSIDE 8" RHC	1
750188	KRC BURNER CARGO	1
750188	KRC BURNER CARGO	1
851257	LAKE PASTURE 4" LOOP -RLC	1
851289	LAMBERT RHC	1
851247	LAMBERT STA	1
851262	LAMBERT STA-RLC	1
851251	LAMBERT STATION	1
752130	MIRANDO DUVAL MAINLINE 8"	2
752130	MIRANDO DUVAL MAINLINE 8"	1
851245	NQ STA 6	1
851320	SUN FIELD STA.	1
752118	THREE RIVERS	1
851342	TIVOLI 6"	1
851315	WEIGANG GATHERING	1
851315	WEIGANG GATHERING	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (32 detail records)

57

Sum

KOCH PL / LONGVIEW

sysid	sysname	Sum Of Leaks
351759	FISHER GATHERING	1
351759	FISHER GATHERING	1

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851361	GLADEWATER GATHERING	1
851361	GLADEWATER GATHERING	4
851361	GLADEWATER GATHERING	1
351752	LACY-SNYDER GATHERING	1
351752	LACY-SNYDER GATHERING	2
351749	MAINLINE	1
851363	MIDDLE 1/3	3
851366	NORTH 1/3 GATHERING	1
851366	NORTH 1/3 GATHERING	1
851366	NORTH 1/3 GATHERING	3
851366	NORTH 1/3 GATHERING	1
351763	STINCHCOMB TRUNKLINE	1
351751	THRASHER GATHERING	2
351751	THRASHER GATHERING	2
Summary for 'ocname' = KOCH PL / LONGVIEW (16 detail records)		26
Sum		

KOCH PL / MEDFORD

sysid	sysname	Sum Of Leaks
950002	BRECKENRIDGE	1
950002	BRECKENRIDGE	1
950002	BRECKENRIDGE	6
950002	BRECKENRIDGE	3
950001	GAINESVILLE	1
950001	GAINESVILLE	5
950001	GAINESVILLE	4
950001	GAINESVILLE	1
851359	MCCAMEY	1
851359	MCCAMEY	2
Summary for 'ocname' = KOCH PL / MEDFORD (10 detail records)		25
Sum		

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KOCH PL / MIDLAND

sysid	sysname	Sum Of Leaks
851221	GARZA SYS.	1
851230	MCELROY GATHERING	1
851230	MCELROY GATHERING	2
851231	QUITO CRUDE GATHERING	1
851231	QUITO CRUDE GATHERING	1
Summary for 'ocname' = KOCH PL / MIDLAND (5 detail records)		6
Sum		
Summary for 'opname' = KOCH PIPELINE CO., L.P. (63 detail records)		114
Sum		

KOCH REFINING COMPANY, L.P.

KOCH REF. LP / CORPUS CHRISTI

sysid	sysname	Sum Of Leaks
751981	TP1-CORPUS TO SAN ANTONIO	1
Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (1 detail record)		1
Sum		
Summary for 'opname' = KOCH REFINING COMPANY, L.P. (1 detail record)		1
Sum		
Summary for 'cause_desc' = CORROSION (101 detail records)		269
Sum		

DAMAGE BY OTHERS

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	Sum Of Leaks
831235	TPL-63 CARTHAGE	1
831308	TPL-86 CARTHAGE	1
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (2 detail records)		2
Sum		

KOCH GATEWAY/LONGVIEW

sysid	sysname	Sum Of Leaks
831356	TPL-1 LONGVIEW	1
831356	TPL-1 LONGVIEW	2

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831356	TPL-1 LONGVIEW	1
831356	TPL-1 LONGVIEW	1
831356	TPL-1 LONGVIEW	2
831353	TPL-11 LONGVIEW	1
831353	TPL-11 LONGVIEW	1
831353	TPL-11 LONGVIEW	2
831353	TPL-11 LONGVIEW	2
831353	TPL-11 LONGVIEW	2
831353	TPL-11 LONGVIEW	1
831353	TPL-11 LONGVIEW	1
831353	TPL-11 LONGVIEW	1
831349	TPL-391 LONGVIEW	1
831358	TPL-4-LONGVIEW	1
831354	TPL-8 LONGVIEW	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (16 detail records)		
Sum		21
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (18 detail records)		
Sum		23

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Leaks
851239	INGELSIDE 8" RHC	1
752119	MAYO	1
851313	POWERS STA. 8"	1
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (3 detail records)		
Sum		3

KOCH PL / LONGVIEW

sysid	sysname	Sum Of Leaks
351749	MAINLINE	1
351749	MAINLINE	1
351749	MAINLINE	1
851363	MIDDLE 1/3	1

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851363	MIDDLE 1/3	1
851366	NORTH 1/3 GATHERING	1
Summary for 'ocname' = KOCH PL / LONGVIEW (6 detail records)		6
Sum		

KOCH PL / MEDFORD

sysid	sysname	Sum Of Leaks
950002	BRECKENRIDGE	1
650199	EP MIX/CHICO-FARMERSVILLE 4", 6"	1
950001	GAINESVILLE	1
851227	GAINESVILLE, BEST DISCH.	1
851228	GAINESVILLE, NOCONA LEG	1
Summary for 'ocname' = KOCH PL / MEDFORD (5 detail records)		5
Sum		

KOCH PL / MIDLAND

sysid	sysname	Sum Of Leaks
851231	QUITO CRUDE GATHERING	1
Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)		1
Sum		
Summary for 'opname' = KOCH PIPELINE CO., L.P. (15 detail records)		15
Sum		

KOCH REFINING COMPANY, L.P.

KOCH REF. LP / CORPUS CHRISTI

sysid	sysname	Sum Of Leaks
751981	TP1-CORPUS TO SAN ANTONIO	1
Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (1 detail record)		1
Sum		
Summary for 'opname' = KOCH REFINING COMPANY, L.P. (1 detail record)		1
Sum		
Summary for 'cause_desc' = DAMAGE BY OTHERS (34 detail records)		39
Sum		

MATERIAL/CONSTRUCTION DEFECT

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	Sum Of Leaks
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831238	391-02-01 CARTHAGE	1
831234	TPL-059 CARTHAGE	1
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (2 detail records)		
Sum		2

KOCH GATEWAY/LONGVIEW

sysid	sysname	Sum Of Leaks
831353	TPL-11 LONGVIEW	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)		
Sum		1
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (3 detail records)		
Sum		3

KOCH PIPELINE CO., L.P.

HAZARDOUS LIQUID SYSTEMS/CORPUS

sysid	sysname	Sum Of Leaks
752125	FALLS CITY STATION TO PETTUS 6"	1
752125	FALLS CITY STATION TO PETTUS 6"	1
Summary for 'ocname' = HAZARDOUS LIQUID SYSTEMS/CORPUS (2 detail records)		
Sum		2

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Leaks
750196	CRUDE/RATTLESNAKE 10"-12"	1
750196	CRUDE/RATTLESNAKE 10"-12"	1
751920	INGLESIDE JCT. 12"	1
851317	SEELIGSON STATION -8"	1
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (4 detail records)		
Sum		4

KOCH PL / LONGVIEW

sysid	sysname	Sum Of Leaks
851366	NORTH 1/3 GATHERING	1
851366	NORTH 1/3 GATHERING	1
Summary for 'ocname' = KOCH PL / LONGVIEW (2 detail records)		
Sum		2

KOCH PL / MEDFORD

sysid	sysname	Sum Of Leaks
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950002	BRECKENRIDGE	1
950001	GAINESVILLE	1
950001	GAINESVILLE	1
950001	GAINESVILLE	1
851359	MCCAMEY	1

Summary for 'ocname' = KOCH PL / MEDFORD (5 detail records)

Sum	5
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KOCH PL / MIDLAND

sysid	sysname	Sum Of Leaks
851232	DRIVER GATHERING	1
851230	MCELROY GATHERING	1
Summary for 'ocname' = KOCH PL / MIDLAND (2 detail records)		
Sum		2
Summary for 'opname' = KOCH PIPELINE CO., L.P. (15 detail records)		
Sum		15
Summary for 'cause_desc' = MATERIAL/CONSTRUCTION DEFECT (18 detail records)		
Sum		18

OTHER

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	Sum Of Leaks
831305	TPL-263 CARTHAGE	1
831305	TPL-263 CARTHAGE	1
831303	TPL-265 CARTHAGE	1
831235	TPL-63 CARTHAGE	2
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (4 detail records)		
Sum		5

KOCH GATEWAY/LONGVIEW

sysid	sysname	Sum Of Leaks
831353	TPL-11 LONGVIEW	1
831351	TPL-65-2 LONGVIEW	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)		
Sum		2

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (6 detail records)
 Sum 7

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	Sum Of Leaks
851239	INGELSIDE 8" RHC	1
752119	MAYO	1
750209	MAYO 10"	1
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (3 detail records)		
Sum		3

KOCH PL / LONGVIEW

sysid	sysname	Sum Of Leaks
351756	ANDERSON GATHERING	1
851361	GLADEWATER GATHERING	1
351753	SNODDY GATHERING	1
Summary for 'ocname' = KOCH PL / LONGVIEW (3 detail records)		
Sum		3

KOCH PL / MEDFORD

sysid	sysname	Sum Of Leaks
950002	BRECKENRIDGE	2
950002	BRECKENRIDGE	2
950002	BRECKENRIDGE	1
950002	BRECKENRIDGE	2
950002	BRECKENRIDGE	1
950001	GAINESVILLE	1
950008	PARDUE	1
Summary for 'ocname' = KOCH PL / MEDFORD (7 detail records)		
Sum		10
Summary for 'opname' = KOCH PIPELINE CO., L.P. (13 detail records)		
Sum		16
Summary for 'cause_desc' = OTHER (19 detail records)		
Sum		23
Grand Total		349

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Annual Leak Occurrence Since 1988

1988

CORROSION

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	3
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)				
Sum				3

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	9
831353	TPL-11 LONGVIEW	O	R	6
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)				
Sum				15
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (3 detail records)				
Sum				18
Summary for 'leak_cause' = C (3 detail records)				
Sum				18

DAMAGE BY OTHERS

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)				
Sum				1
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (1 detail record)				
Sum				1
Summary for 'leak_cause' = D (1 detail record)				
Sum				1

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RRCII 02275

Summary for 'leak_yr' = 1988 (4 detail records)
Sum

19

1989**CORROSION****KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	11

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)
Sum

11

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	8
831353	TPL-11 LONGVIEW	O	R	5
831349	TPL-391 LONGVIEW	O	R	1

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (3 detail records)
Sum

14

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (4 detail records)
Sum

25

KOCH PIPELINE CO., L.P.**KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851315	WEIGANG GATHERING	I	N	1
851321	GARCIA MAIN GATHERING 4"	I	N	3
851341	12" RLC TIE-IN	I	N	3

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (3 detail records)
Sum

7

Summary for 'opname' = KOCH PIPELINE CO., L.P. (3 detail records)
Sum

7

Summary for 'leak_cause' = C (7 detail records)
Sum

32

DAMAGE BY OTHERS

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KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	2
831353	TPL-11 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)				
Sum				3
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)				
Sum				3
Summary for 'leak_cause' = D (2 detail records)				
Sum				3

OTHER

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)				
Sum				1
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (1 detail record)				
Sum				1
Summary for 'leak_cause' = O (1 detail record)				
Sum				1
Summary for 'leak_yr' = 1989 (10 detail records)				
Sum				36

1990

CORROSION

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	req_status	Sum Of Leaks
831234	TPL-059 CARTHAGE	O	R	1
831235	TPL-63 CARTHAGE	O	R	5

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RRCII 02277

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (2 detail records)

Sum 6

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	8
831349	TPL-391 LONGVIEW	O	R	1
831353	TPL-11 LONGVIEW	O	R	10

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (3 detail records)

Sum 19

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (5 detail records)

Sum 25

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	req_status	Sum Of Leaks
851343	HEYSER STA 6"	I	N	1
750188	KRC BURNER CARGO	I	R	1
851315	WEIGANG GATHERING	I	N	1
851320	SUN FIELD STA.	I	N	1
851341	12" RLC TIE-IN	I	N	6
851342	TIVOLI 6"	I	N	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (6 detail records)

Sum 11

Summary for 'opname' = KOCH PIPELINE CO., L.P. (6 detail records)

Sum 11

Summary for 'leak_cause' = C (11 detail records)

Sum 36

DAMAGE BY OTHERS

KOCH PIPELINE CO., L.P.

KOCH PL / LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
351749	MAINLINE	I	N	1

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Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)	
Sum	1
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)	
Sum	1
Summary for 'leak_cause' = D (1 detail record)	
Sum	1
Summary for 'leak_yr' = 1990 (12 detail records)	
Sum	37

1991

CORROSION**KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	req_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	4
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)				
Sum				4

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	2
831356	TPL-1 LONGVIEW	O	R	1
831349	TPL-391 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (3 detail records)				
Sum				4
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (4 detail records)				
Sum				8

KOCH PIPELINE CO., L.P.**KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	req_status	Sum Of Leaks
752130	MIRANDO DUVAL MAINLINE 8"	I	N	2
851341	12" RLC TIE-IN	I	N	6
451178	GERDES TO THREE WAY TRAP	I	N	1
851343	HEYSER STA 6"	I	N	2

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RRCII 02279

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (4 detail records)

Sum 11

KOCH PL / LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
351752	LACY-SNYDER GATHERING	I	N	2
851361	GLADEWATER GATHERING	I	N	1
851363	MIDDLE 1/3	I	N	3
851366	NORTH 1/3 GATHERING	I	N	1
351763	STINCHCOMB TRUNKLINE	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (5 detail records)

Sum 8

Summary for 'opname' = KOCH PIPELINE CO., L.P. (9 detail records)

Sum 19

KOCH REFINING COMPANY, L.P.

KOCH REF. LP / CORPUS CHRISTI

sysid	sysname	intra_int	reg_status	Sum Of Leaks
751981	TP1-CORPUS TO SAN ANTONIO	I	R	1

Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (1 detail record)

Sum 1

Summary for 'opname' = KOCH REFINING COMPANY, L.P. (1 detail record)

Sum 1

Summary for 'leak_cause' = C (14 detail records)

Sum 28

DAMAGE BY OTHERS

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	1
831356	TPL-1 LONGVIEW	O	R	1

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)

Sum 2

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)
 Sum

2

KOCH PIPELINE CO., L.P.

KOCH PL / LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851366	NORTH 1/3 GATHERING	I	N	1
851363	MIDDLE 1/3	I	N	1
351749	MAINLINE	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (3 detail records)
 Sum

3

Summary for 'opname' = KOCH PIPELINE CO., L.P. (3 detail records)
 Sum

3

Summary for 'leak_cause' = D (5 detail records)
 Sum

5

OTHER

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831305	TPL-263 CARTHAGE	O	R	1
831303	TPL-265 CARTHAGE	O	R	1

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (2 detail records)
 Sum

2

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)
 Sum

2

Summary for 'leak_cause' = O (2 detail records)
 Sum

2

Summary for 'leak_yr' = 1991 (21 detail records)
 Sum

35

1992

CORROSION

KOCH GATEWAY PIPELINE COMPANY

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RRCH 02281

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	1
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)				
Sum				1

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	16
831354	TPL-8 LONGVIEW	O	R	1
831358	TPL-4 LONGVIEW	O	R	1
831353	TPL-11 LONGVIEW	O	R	12
831349	TPL-391 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (5 detail records)				
Sum				31
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (6 detail records)				
Sum				32

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851341	12" RLC TIE-IN	I	N	6
851321	GARCIA MAIN GATHERING 4"	I	N	2
851343	HEYSEY STA 6"	I	N	2
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (3 detail records)				
Sum				10

KOCH PL / LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851361	GLADEWATER GATHERING	I	N	4
851366	NORTH 1/3 GATHERING	I	N	3
Summary for 'ocname' = KOCH PL / LONGVIEW (2 detail records)				
Sum				7

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RRCII 02282

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	6
851359	MCCAMEY	O	R	1
Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				7
Sum				

KOCH PL / MIDLAND

sysid	sysname	intra_int	req_status	Sum Of Leaks
851231	QUITO CRUDE GATHERING	I	N	1
Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)				1
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (8 detail records)				25
Sum				
Summary for 'leak_cause' = C (14 detail records)				57
Sum				

DAMAGE BY OTHERS

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	req_status	Sum Of Leaks
831308	TPL-86 CARTHAGE	O	R	1
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)				1
Sum				

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	1
831349	TPL-391 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)				2
Sum				
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (3 detail records)				3
Sum				

KOCH PIPELINE CO., L.P.

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RRCII 02283

KOCH PL / LONGIVEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851363	MIDDLE 1/3	I	N	1
Summary for 'ocname' = KOCH PL / LONGIVEW (1 detail record)				1
Sum				1

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	1
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				1
Sum				1
Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)				2
Sum				2
Summary for 'leak_cause' = D (5 detail records)				5
Sum				5

MATERIAL/CONSTRUCTION DEFECT

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	1
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				1
Sum				1
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)				1
Sum				1
Summary for 'leak_cause' = M (1 detail record)				1
Sum				1

OTHER

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	2
831305	TPL-263 CARTHAGE	O	R	1

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RRCII 02284

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (2 detail records)

Sum 3

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)

Sum 3

KOCH PIPELINE CO., L.P.**KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	req_status	Sum Of Leaks
752119	MAYO	I	R	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)

Sum 1

KOCH PL / LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
851361	GLADEWATER GATHERING	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)

Sum 1

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	2

Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)

Sum 2

Summary for 'opname' = KOCH PIPELINE CO., L.P. (3 detail records)

Sum 4

Summary for 'leak_cause' = O (5 detail records)

Sum 7

Summary for 'leak_yr' = 1992 (25 detail records)

Sum 70

1993**CORROSION****KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	req_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	5

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Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)

Sum

5

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831351	TPL-65-2 LONGVIEW	O	R	1
831358	TPL-4-LONGVIEW	O	R	1
831356	TPL-1 LONGVIEW	O	R	15

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (3 detail records)

Sum

17

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (4 detail records)

Sum

22

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	req_status	Sum Of Leaks
851321	GARCIA MAIN GATHERING 4"	I	N	2
750188	KRC BURNER CARGO	I	R	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (2 detail records)

Sum

3

KOCH PL / LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
851366	NORTH 1/3 GATHERING	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)

Sum

1

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	1
950001	GAINESVILLE	I	N	1
851359	MCCAMEY	O	R	2

Summary for 'ocname' = KOCH PL / MEDFORD (3 detail records)

Sum

4

Summary for 'opname' = KOCH PIPELINE CO., L.P. (6 detail records)

Sum

8

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Summary for 'leak_cause' = C (10 detail records)
Sum

30

DAMAGE BY OTHERS**KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/LONGVIEW**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	2
831354	TPL-8 LONGVIEW	O	R	1
831353	TPL-11 LONGVIEW	O	R	2

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (3 detail records)
Sum

5

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (3 detail records)
Sum

5

KOCH PIPELINE CO., L.P.**KOCH PL / MEDFORD**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950001	GAINESVILLE	I	N	1

Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)
Sum

1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)
Sum

1

Summary for 'leak_cause' = D (4 detail records)
Sum

6

MATERIAL/CONSTRUCTION DEFECT**KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831234	TPL-059 CARTHAGE	O	R	1

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)
Sum

1

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (1 detail record)
Sum

1

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KOCH PIPELINE CO., L.P.

KOCH PL / LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851366	NORTH 1/3 GATHERING	I	N	1
Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)				1
Sum				

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950001	GAINESVILLE	I	N	1
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				1
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)				2
Sum				
Summary for 'leak_cause' = M (3 detail records)				3
Sum				

OTHER

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831351	TPL-65-2 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)				1
Sum				
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (1 detail record)				1
Sum				

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	1
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				1
Sum				

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RRCII 02288

Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)

1

Sum

Summary for 'leak_cause' = O (2 detail records)

2

Sum

Summary for 'leak_yr' = 1993 (19 detail records)

41

Sum

1994**CORROSION****KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	req_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	3

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)

3

Sum

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	3
831353	TPL-11 LONGVIEW	O	R	2

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)

5

Sum

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (3 detail records)

8

Sum

KOCH PIPELINE CO., L.P.**KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	req_status	Sum Of Leaks
752118	THREE RIVERS	I	R	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)

1

Sum

KOCH PL / LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
351751	THRASHER GATHERING	I	N	2

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RRCII 02289

Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)
Sum

2

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	1

Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)
Sum

1

KOCH PL / MIDLAND

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851231	QUITO CRUDE GATHERING	I	N	1

Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)
Sum

1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (4 detail records)
Sum

5

Summary for 'leak_cause' = C (7 detail records)
Sum

13

DAMAGE BY OTHERS

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	2
831356	TPL-1 LONGVIEW	O	R	1

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)
Sum

3

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)
Sum

3

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	reg_status	Sum Of Leaks
752119	MAYO	I	R	1

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RRCII 02290

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)

Sum 1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)

Sum 1

Summary for 'leak_cause' = D (3 detail records)

Sum 4

MATERIAL/CONSTRUCTION DEFECT**KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/LONGVIEW**

sysid	sysname	intra_int	req_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	1

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)

Sum 1

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (1 detail record)

Sum 1

Summary for 'leak_cause' = M (1 detail record)

Sum 1

OTHER**KOCH PIPELINE CO., L.P.****KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	req_status	Sum Of Leaks
750209	MAYO 10"	I	R	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)

Sum 1

KOCH PL / LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
351753	SNODDY GATHERING	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)

Sum 1

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	2

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RRCII 02291

Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)	
Sum	2
Summary for 'opname' = KOCH PIPELINE CO., L.P. (3 detail records)	
Sum	4
Summary for 'leak_cause' = O (3 detail records)	
Sum	4
Summary for 'leak_yr' = 1994 (14 detail records)	
Sum	22

1995**CORROSION****KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	1
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)				
Sum				1

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831356	TPL-1 LONGVIEW	O	R	1
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)				
Sum				1
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)				
Sum				2

KOCH PIPELINE CO., L.P.**KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851251	LAMBERT STATION	I	N	1
851248	CLAUDE HEARDE	I	N	1
851262	LAMBERT STA-RLC	I	N	1
750196	CRUDE/RATTLESNAKE 10"-12"	I	R	2
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (4 detail records)				
Sum				5

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RRCII 02292

KOCH PL / LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851366	NORTH 1/3 GATHERING	I	N	1
851361	GLADEWATER GATHERING	I	N	1
Summary for 'ocname' = KOCH PL / LONGVIEW (2 detail records)				2
Sum				

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950001	GAINESVILLE	I	N	5
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				5
Sum				

KOCH PL / MIDLAND

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851230	MCELROY GATHERING	I	N	1
851221	GARZA SYS.	I	N	1
Summary for 'ocname' = KOCH PL / MIDLAND (2 detail records)				2
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (9 detail records)				14
Sum				
Summary for 'leak_cause' = C (11 detail records)				16
Sum				

DAMAGE BY OTHERS

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	2
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)				2
Sum				
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (1 detail record)				2
Sum				

KOCH PIPELINE CO., L.P.

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RRCH 02293

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
851228	GAINESVILLE, NOCONA LEG	O	N	1
Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)				1
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)				1
Sum				
Summary for 'leak_cause' = D (2 detail records)				3
Sum				

MATERIAL/CONSTRUCTION DEFECT

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	req_status	Sum Of Leaks
750196	CRUDE/RATTLESNAKE 10"-12"	I	R	1
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)				1
Sum				

KOCH PL / LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
851366	NORTH 1/3 GATHERING	I	N	1
Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)				1
Sum				

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950001	GAINESVILLE	I	N	1
851359	MCCAMEY	O	R	1
Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				2
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (4 detail records)				4
Sum				
Summary for 'leak_cause' = M (4 detail records)				4
Sum				

OTHER

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RRCII 02294

KOCH PIPELINE CO., L.P.

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	1
950001	GAINESVILLE	I	N	1
Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				2
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)				2
Sum				
Summary for 'leak_cause' = O (2 detail records)				2
Sum				
Summary for 'leak_yr' = 1995 (19 detail records)				25
Sum				

1996

CORROSION

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	req_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	2
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)				2
Sum				

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	1
831356	TPL-1 LONGVIEW	O	R	4
Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)				5
Sum				
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (3 detail records)				7
Sum				

KOCH PIPELINE CO., L.P.

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RRC# 02295

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	req_status	Sum Of Leaks
851245	NQ STA 6	I	N	1
752130	MIRANDO DUVAL MAINLINE 8"	I	N	1
750196	CRUDE/RATTLESNAKE 10"-12"	I	R	1
851268	COPANO B1 & E3 TO COPANO Y JCT-RLC	I	N	1
851247	LAMBERT STA	I	N	1
851257	LAKE PASTURE 4" LOOP -RLC	I	N	1
851239	INGELSIDE 8" RHC	I	N	1
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (7 detail records)				7
Sum				

KOCH PL / LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
351752	LACY-SNYDER GATHERING	I	N	1
351759	FISHER GATHERING	I	N	1
Summary for 'ocname' = KOCH PL / LONGVIEW (2 detail records)				2
Sum				

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950001	GAINESVILLE	I	N	4
950002	BRECKENRIDGE	I	N	3
Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				7
Sum				

KOCH PL / MIDLAND

sysid	sysname	intra_int	req_status	Sum Of Leaks
851230	MCELROY GATHERING	I	N	2
Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)				2
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (12 detail records)				18
Sum				
Summary for 'leak_cause' = C (15 detail records)				25
Sum				

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RRCII 02296

DAMAGE BY OTHERS**KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831235	TPL-63 CARTHAGE	O	R	1

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)
Sum

1

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	1

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (1 detail record)
Sum

1

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)
Sum

2

KOCH PIPELINE CO., L.P.**KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851239	INGELSIDE 8" RHC	I	N	1
851313	POWERS STA. 8"	I	N	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (2 detail records)
Sum

2

Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)
Sum

2

Summary for 'leak_cause' = D (4 detail records)
Sum

4

MATERIAL/CONSTRUCTION DEFECT**KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/CARTHAGE**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
831238	391-02-01 CARTHAGE	O	R	1

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RRCII 02297

Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)

Sum

1

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (1 detail record)

Sum

1

KOCH PIPELINE CO., L.P.**HAZARDOUS LIQUID SYSTEMS/CORPUS**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
752125	FALLS CITY STATION TO PETTUS 6"	I	R	1

Summary for 'ocname' = HAZARDOUS LIQUID SYSTEMS/CORPUS (1 detail record)

Sum

1

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851317	SEELIGSON STATION -8"	I	N	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)

Sum

1

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950001	GAINESVILLE	I	N	1

Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)

Sum

1

KOCH PL / MIDLAND

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851232	DRIVER GATHERING	I	N	1
851230	MCELROY GATHERING	I	N	1

Summary for 'ocname' = KOCH PL / MIDLAND (2 detail records)

Sum

2

Summary for 'opname' = KOCH PIPELINE CO., L.P. (5 detail records)

Sum

5

Summary for 'leak_cause' = M (6 detail records)

Sum

6

OTHER

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RRCII 02298

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	req_status	Sum Of Leaks
851239	INGELSIDE 8" RHC	I	N	1
Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (1 detail record)				1
Sum				

KOCH PL / MEDFORD

sysid	sysname	intra_int	req_status	Sum Of Leaks
950002	BRECKENRIDGE	I	N	2
950008	PARDUE	I	N	1
Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				3
Sum				
Summary for 'opname' = KOCH PIPELINE CO., L.P. (3 detail records)				4
Sum				
Summary for 'leak_cause' = O (3 detail records)				4
Sum				
Summary for 'leak_yr' = 1996 (28 detail records)				39
Sum				

1997

CORROSION

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

sysid	sysname	intra_int	req_status	Sum Of Leaks
831234	TPL-059 CARTHAGE	O	R	1
Summary for 'ocname' = KOCH GATEWAY/CARTHAGE (1 detail record)				1
Sum				

KOCH GATEWAY/LONGVIEW

sysid	sysname	intra_int	req_status	Sum Of Leaks
831353	TPL-11 LONGVIEW	O	R	4
831354	TPL-8 LONGVIEW	O	R	2

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RRCII 02299

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)

Sum

6

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (3 detail records)

Sum

7

KOCH PIPELINE CO., L.P.**KOCH PL / CORPUS CHRISTI**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851290	B1 RLC	I	N	1
851289	LAMBERT RHC	I	N	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (2 detail records)

Sum

2

KOCH PL / LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
351759	FISHER GATHERING	I	N	1
351751	THRASHER GATHERING	I	N	2
351749	MAINLINE	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (3 detail records)

Sum

4

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
950001	GAINESVILLE	I	N	1

Summary for 'ocname' = KOCH PL / MEDFORD (1 detail record)

Sum

1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (6 detail records)

Sum

7

Summary for 'leak_cause' = C (9 detail records)

Sum

14

DAMAGE BY OTHERS**KOCH GATEWAY PIPELINE COMPANY****KOCH GATEWAY/LONGVIEW**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
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RRCII 02300

831358	TPL-4-LONGVIEW	O	R	1
831356	TPL-1 LONGVIEW	O	R	1

Summary for 'ocname' = KOCH GATEWAY/LONGVIEW (2 detail records)				
Sum				2
Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)				
Sum				2

KOCH PIPELINE CO., L.P.**KOCH PL / LONGVIEW**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
351749	MAINLINE	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)				
Sum				1

KOCH PL / MEDFORD

sysid	sysname	intra_int	reg_status	Sum Of Leaks
650199	EP MIX/CHICO-FARMERSVILLE 4", 6"	I	R	1
851227	GAINESVILLE, BEST DISCH.	O	N	1

Summary for 'ocname' = KOCH PL / MEDFORD (2 detail records)				
Sum				2

KOCH PL / MIDLAND

sysid	sysname	intra_int	reg_status	Sum Of Leaks
851231	QUITO CRUDE GATHERING	I	N	1

Summary for 'ocname' = KOCH PL / MIDLAND (1 detail record)				
Sum				1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (4 detail records)				
Sum				4

KOCH REFINING COMPANY, L.P.**KOCH REF. LP / CORPUS CHRISTI**

sysid	sysname	intra_int	reg_status	Sum Of Leaks
751981	TP1-CORPUS TO SAN ANTONIO	I	R	1

Summary for 'ocname' = KOCH REF. LP / CORPUS CHRISTI (1 detail record)				
Sum				1

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RRCII 02301

Summary for 'opname' = KOCH REFINING COMPANY, L.P. (1 detail record)

Sum

1

Summary for 'leak_cause' = D (7 detail records)

Sum

7

MATERIAL/CONSTRUCTION DEFECT

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

sysid	sysname	intra_int	reg_status	Sum Of Leaks
750196	CRUDE/RATTLESNAKE 10"-12"	I	R	1
751920	INGLESIDE JCT. 12"	I	R	1

Summary for 'ocname' = KOCH PL / CORPUS CHRISTI (2 detail records)

Sum

2

Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)

Sum

2

Summary for 'leak_cause' = M (2 detail records)

Sum

2

OTHER

KOCH PIPELINE CO., L.P.

KOCH PL / LONGVIEW

sysid	sysname	intra_int	reg_status	Sum Of Leaks
351756	ANDERSON GATHERING	I	N	1

Summary for 'ocname' = KOCH PL / LONGVIEW (1 detail record)

Sum

1

Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)

Sum

1

Summary for 'leak_cause' = O (1 detail record)

Sum

1

Summary for 'leak_yr' = 1997 (19 detail records)

Sum

24

86

MATERIAL/CONSTRUCTION DEFECT

KOCH PIPELINE CO., L.P.

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RRCII 02302

HAZARDOUS LIQUID SYSTEMS/CORPUS

sysid	sysname	intra_int	req_status	Sum Of Leaks
752125	FALLS CITY STATION TO PETTUS 6"	I	R	1
Summary for 'ocname' = HAZARDOUS LIQUID SYSTEMS/CORPUS (1 detail record)				1
Sum				1
Summary for 'opname' = KOCH PIPELINE CO., L.P. (1 detail record)				1
Sum				1
Summary for 'leak_cause' = M (1 detail record)				1
Sum				1
Summary for 'leak_yr' = 96 (1 detail record)				1
Sum				1
Grand Total				349

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RRCH 02303

Miles of Pipe: Instrumented Internal Inspection

Gasoline, Diesel

KOCH PIPELINE CO., L.P.

sysid	sysname	Pig Date	reg	Sum Of Miles
651441	DFW 8"	7/10/95	R	8.1
651440	SOUTHLAKE 12"	8/11/95	R	12.0
450937	STAR 8"	8/17/95	R	3.2
450938	MARLIN TO TEMPLE 4" (SOUTHWEST PIPELINE)	2/1/97	R	38.6
Summary for 'opname' = KOCH PIPELINE CO., L.P. (4 detail records)				61.9
Sum				

KOCH REFINING COMPANY, L.P.

sysid	sysname	Pig Date	reg	Sum Of Miles
652087	TP11-WACO TO EULESS	8/14/95	R	106.0
451141	TP1-AUSTIN TO WACO	8/2/95	R	110.0
451137	TP1-SAN ANTONIO TO AUSTIN	7/25/95	R	95.0
751981	TP1-CORPUS TO SAN ANTONIO	10/10/95	R	134.5
Summary for 'opname' = KOCH REFINING COMPANY, L.P. (4 detail records)				445.5
Sum				
Summary for 'product' = Gasoline, Diesel (8 detail records)				507.4
Sum				

Liquefied Petroleum Gas

KOCH HYDROCARBON COMPANY

sysid	sysname	Pig Date	reg	Sum Of Miles
250711	NGL/SONORA TO ROBERT RANCH	9/19/94	R	172.0
Summary for 'opname' = KOCH HYDROCARBON COMPANY (1 detail record)				172.0
Sum				

KOCH PIPELINE CO., L.P.

sysid	sysname	Pig Date	reg	Sum Of Miles
851346	CHAPARRAL PIPELINE	5/1/87	R	514.0
752120	KRC 6" & 8" PROPYLENE/PROPANE	5/1/96	R	8.0

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RRCII 02304

Summary for 'opname' = KOCH PIPELINE CO., L.P. (2 detail records)

522.0

Sum

Summary for 'product' = Liquefied Petroleum Gas (3 detail records)

694.0

Sum

Natural Gas

KOCH GATEWAY PIPELINE COMPANY

sysid	sysname	Pig Date	reg	Sum Of Miles
831310	TPL-65 CARTHAGE	4/1/94	R	1.8
831303	TPL-265 CARTHAGE	4/5/94	R	4.1

Summary for 'opname' = KOCH GATEWAY PIPELINE COMPANY (2 detail records)

5.9

Sum

Summary for 'product' = Natural Gas (2 detail records)

5.9

Sum

Petroleum Crude Oil

KOCH PIPELINE CO., L.P.

sysid	sysname	Pig Date	reg	Sum Of Miles
451180	ROSAKNY STATION TO NIXON	10/21/96	N	55.8
451173	SHAFT TO HEARNE STA.	9/23/96	N	21.3
451174	SHAFT TO GERDES	9/23/96	N	23.6
451176	WEST POINT TO THREE WAY	9/19/96	N	3.0
451179	THREE WAY TRAP TO ROSANKY STATION	10/21/96	N	12.4
851313	POWERS STA. 8"	6/9/97	N	39.1
451181	NIXON TO PETTUS	10/18/96	N	45.9
451178	GERDES TO THREE WAY TRAP	12/18/96	N	32.3
752130	MIRANDO DUVAL MAINLINE 8"	9/1/97	N	38.0
851240	REFUGIO 8" RHC	4/4/97	N	7.1
851317	SEELIGSON STATION -8"	11/1/93	N	50.8
851319	KELSEY 6"	10/1/93	N	11.0
851341	12" RLC TIE-IN	4/17/97	N	32.0
351749	MAINLINE	6/11/97	N	5.4
351758	RODDEN GATHERING	5/24/97	N	2.3
851347	POWELL GATHERING	5/22/97	N	1.4

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551956	NEEDERLAND 8"	9/1/97	N	64.0
851229	CRUDE/MUENSTER	8/15/97	N	31.2
851239	INGELSIDE 8" RHC	9/1/96	N	28.2
750120	EAST WHITE POINT 10"	4/25/97	R	5.2
752117	LEOPARD #2	12/18/96	R	23.5
750183	KRC 12"	2/15/94	R	4.0
750185	VIOLA CRUDE PIPELINE #1	8/8/97	R	24.5
750188	KRC BURNER CARGO	7/3/96	R	7.0
750194	VIOLA 16"	4/15/95	R	32.4
750199	LAMBERT 10" CRUDE PIPELINE	4/16/97	R	4.1
750207	AGUA DULCE 10"	3/19/96	R	29.0
750209	MAYO 10"	4/27/97	R	28.0
751852	KRC EAST 10"	8/22/97	R	6.7
751920	INGLESIDE JCT. 12"	12/20/96	R	28.0
752117	LEOPARD #2	8/8/96	R	24.5
752118	THREE RIVERS	2/1/95	R	62.4
752119	MAYO	7/8/97	R	62.1
851359	MCCAMEY	6/1/95	R	317.3
752116	REFUGIO 12" CRUDE PIPELINE	4/16/97	R	29.5
Summary for 'opname' = KOCH PIPELINE CO., L.P. (35 detail records)				1193.2
Sum				
Summary for 'product' = Petroleum Crude Oil (35 detail records)				1193.2
Sum				2400.5
Grand Total				

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RRCII 02306

F

RRCII 02307

Violation Summary

RRCII 02308

Violation Summary

Violations of rules in Part 192 for natural gas and Part 195 for hazardous liquids were divided into three categories to identify the nature of problems found. These categories are as follows:

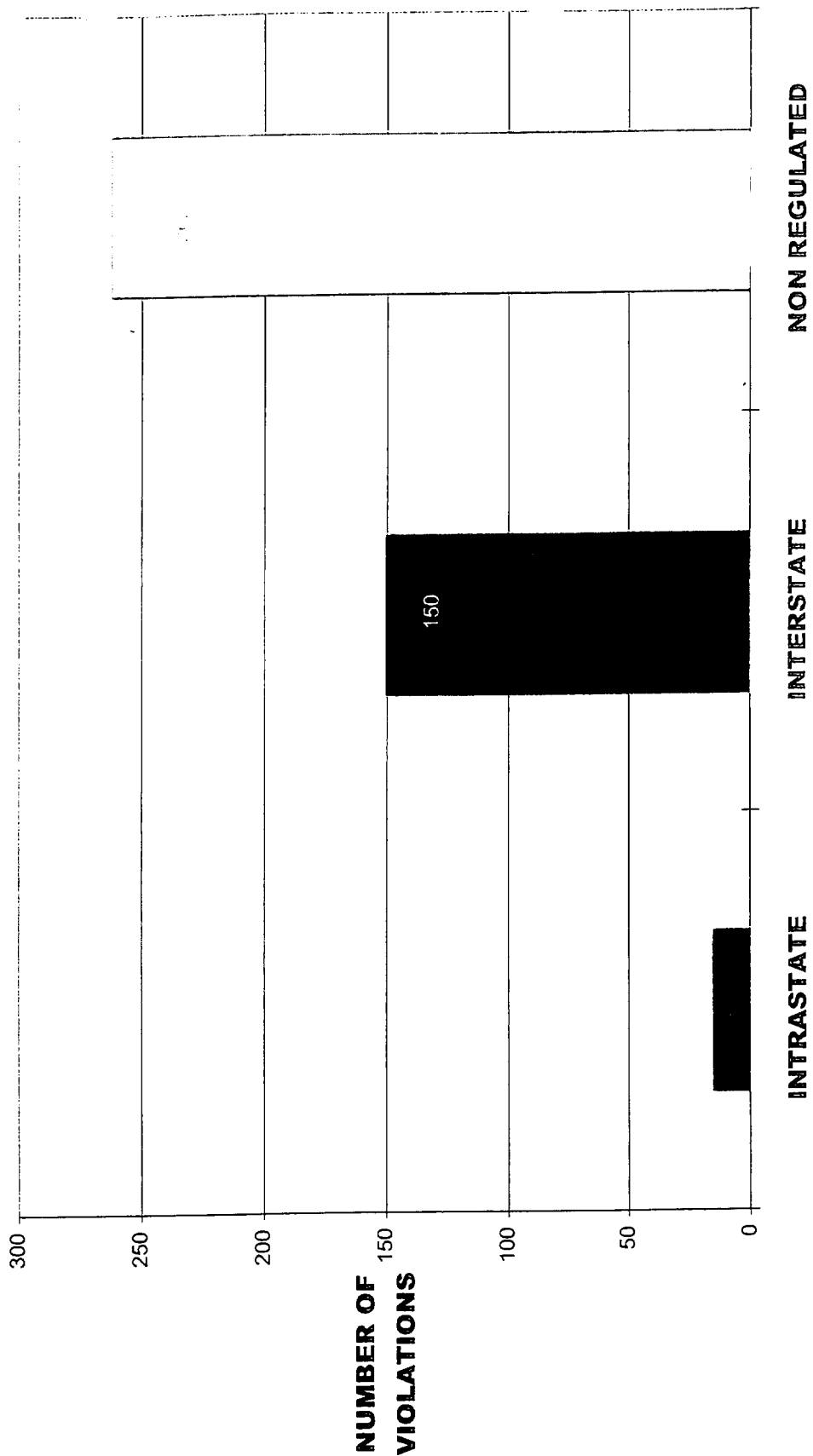
I - Inspection or test not performed

P - Physical deficiency of the pipeline facility

R - Record, procedure or program not established or maintained

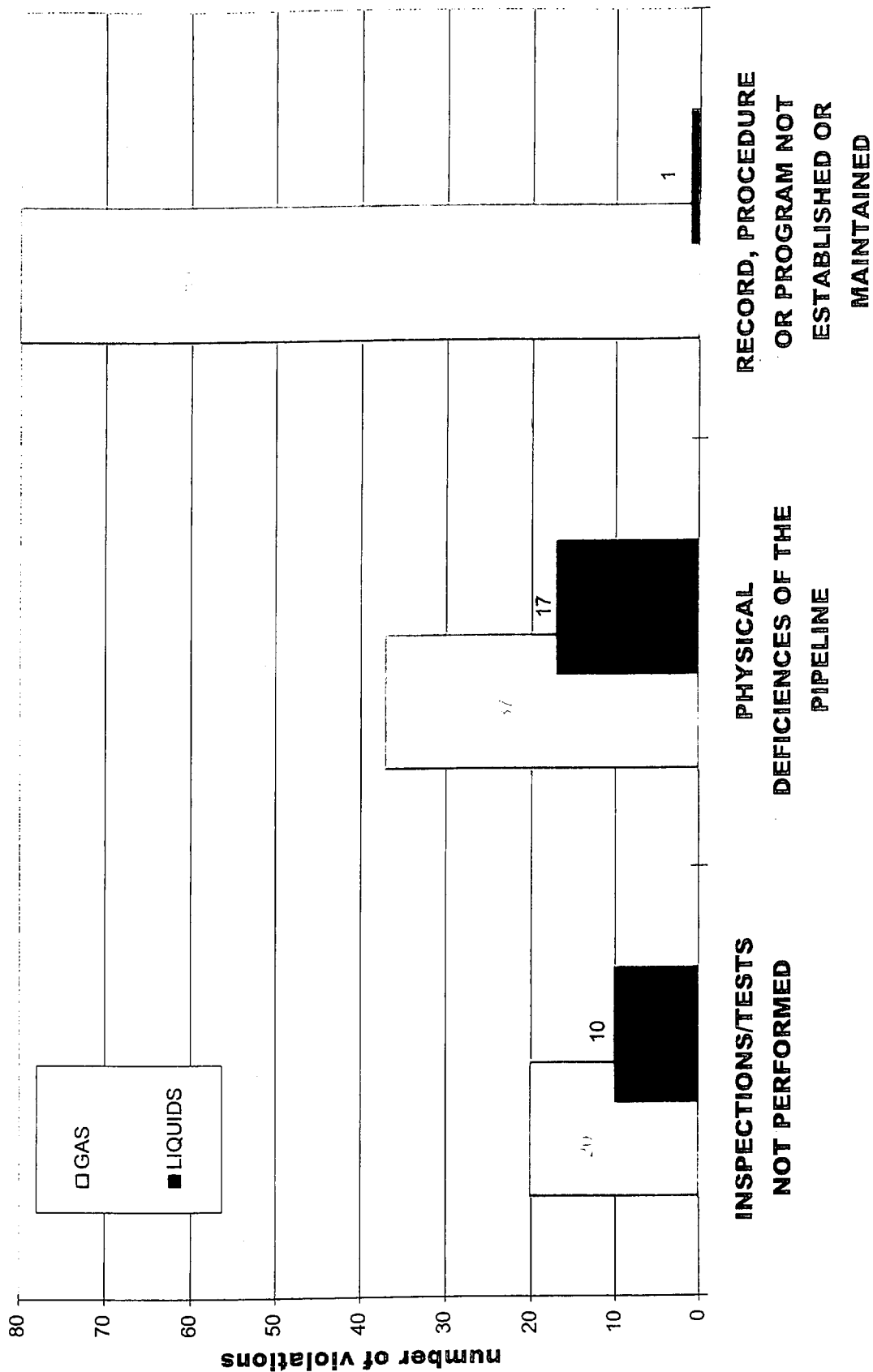
The following report gives occurrences of the violations.

VIOLATIONS BY JURISDICTION



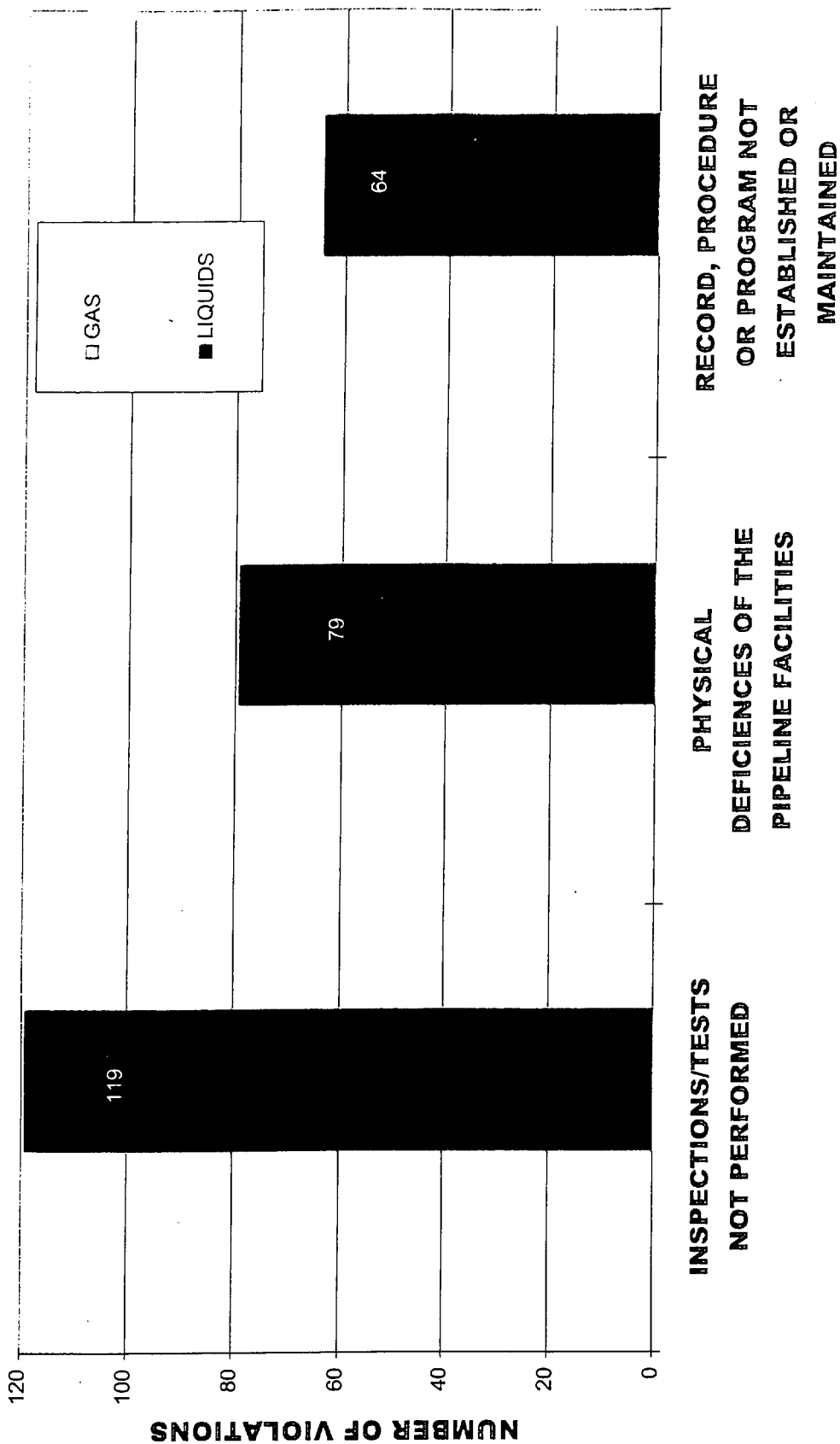
RRCH 02310

VIOLATION CATEGORIES: REGULATED SYSTEMS



RRCII 02311

VIOLATION CATEGORIES: NON REGULATED SYSTEMS



RRCH 02312

Violation Summary

Gas/Liquid Violation: Natural Gas: 49 CFR Part 192

Violation Type: Inspection or test not performed

viol_cod	viol_text	vio_r	vio_n	vio_occ
743002	Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months. Requirement: 49 CFR 192.743(b)	9	0	9
745001	The listed transmission line valve(s) that might be required during an emergency was not inspected and partially operated at the prescribed interval. Requirement: 49 CFR 192.745	3	0	3
705002	Patrols on the transmission line right-of-way were not conducted within the specified intervals. Requirement: 49 CFR 192.705(b)	3	0	3
739001	The following pressure limiting station(s), relief device(s), pressure regulator station(s) or equipment was not inspected and tested at the specified interval to determine if it was: a. In good mechanical condition. b. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed. c. Set to function at the correct pressure. d. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation. Requirement: 49 CFR 192.739	2	0	2
465001	The cathodic protection system at the listed location(s) has not been monitored at least once each calendar year, within intervals not exceeding 15 months. Requirement: 49 CFR 192.465(a)	1	0	1
705001	There was no patrol program to observe surface conditions on and adjacent to the transmission line right-of-way. Requirement: 49 CFR 192.705(a)	1	0	1

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RRCII 02313

479003	Aboveground pipeline was exposed to the atmosphere at the following site(s), but areas of atmospheric corrosion had not been determined.	1	0	1
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Requirement: 49 CFR 192.479(b)(1)

Summary for 'vio_class' = 1 (7 detail records)

Sum	20	0	20
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Violation Type: Physical deficiency of the pipeline facility

viol_cod	viol_text	vio_r	vio_n	vio_occ
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations. Requirement: 49 CFR 192.463(a)	9	0	9
465006	Prompt remedial action was not taken to correct cathodic protection deficiencies found at the listed location(s): Requirement: 49 CFR 192.465(d)	4	0	4
179005	The blowdown discharge at the following location was not located so that the gas could be blown to the atmosphere without undue hazard. Requirement: 49 CFR 192.179(c)	4	0	4
479001	The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating. Requirement: 49 CFR 192.479(a)	4	0	4
199006	The pressure relief or limiting device(s) at the location(s) below had discharge stacks, vents, or outlet ports that were not designed or installed to discharge gas into the atmosphere without undue hazard. Requirement: 49 CFR 192.199(e)	3	0	3
707100	Line markers on mains or transmission lines were inadequate because of the following reason(s): They did not have the operator's name and/or 24 hour telephone number and area code. Requirement: 49 CFR 192.707(d)	2	0	2
323004	Casing used for the pipeline under a railroad or highway at the following location(s) had vents not protected from the weather to prevent water from entering the casing. Requirement: 49 CFR 192.323(d)	2	0	2

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RRCII 02314

479004	Atmospheric corrosion was found on the exposed aboveground pipe at the listed location(s), and remedial measures were not taken to the extent required by 49 CFR 192.485, 192.487, or 192.489. Requirement: 49 CFR 192.479(b)(2)	2	0	2
707002	Line markers were not placed or maintained along the following publicly accessible, above ground main or transmission line. Requirement: 49 CFR 192.707(c)	2	0	2
161005	The support(s) or anchor(s) on the exposed pipeline listed below was/were not made of durable, noncombustible material. Requirement: 49 CFR 192.161(c)	1	0	1
317003	The aboveground transmission line(s) or main(s) at the location(s) below was/were not protected from accidental damage by vehicular traffic or other similar causes. Requirement: 49 CFR 192.317(b)	1	0	1
199010	The valve located in the regulator station bypass at the listed location(s) was not designed to prevent unauthorized operation that could make the pressure regulating or limiting device ineffective. Requirement: 49 CFR 192.199(h)	1	0	1
199009	The pressure relief or limiting device(s) at the location(s) below was not designed to prevent an unauthorized person from operating any stop valve that would make the device inoperable. Requirement: 49 CFR 192.199(h)	1	0	1
179002	Operating devices for sectionalizing block valves were not readily accessible or were not protected from tampering and damage. Requirement: 49 CFR 192.179(b)(1)	1	0	1

Summary for 'vio_class' = P (14 detail records)

Sum

37 0 37

Violation Type: Record, procedure or program not established or maintained

viol_cod	viol_text	vio_r	vio_n	vio_occ
616001	There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency. Requirement: 49 CFR 192.616	24	0	24

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RRCII 02315

614002	The written damage prevention program was insufficient in the following areas:	24	0	24
	a. Records of excavation - related persons were not maintained or were not current.			
	b. Procedures for notification to the public of the program and its purpose were not available or were not followed.			
	c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.			
	Requirement: 49 CFR 192.614(b)			
615012	A liaison had not been established and/or maintained with appropriate fire, police and other public officials.	23	0	23
	Requirement: 49 CFR 192.615(c)			
	A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.			
603300	Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:	2	0	2
	Valve Inspection Records.			
	Requirement: 49 CFR 192.603(b)			
603100	Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:	2	0	2
	a. Patrolling Records.			
	b. Valve Inspection Records.			
	c. Atmospheric Corrosion Records			
	Requirement: 49 CFR 192.603(b)			
491005	There were no records, or records were insufficient, for the listed corrosion control tests, surveys, or inspections.	1	0	1
	Requirement: 49 CFR 192.491(b)(2)			

603500 Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:

1 0 1

Road and Railroad Crossing Patrol Records

Requirement: 49 CFR 192.603(b)

603200 Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:

1 0 1

a. Inspection /Monitoring Pressure Regulating Station

b. Inspection/Monitoring Overpressure Protection Equipment

Requirement: 49 CFR 192.603(b)

603400 Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:

1 0 1

A. Road and Railroad Patrol Records

B. Leak Survey Records

Requirement: 49 CFR 192.603(b)

615002 The written emergency plan did not include procedures for the following item(s):

1 0 1

- a. Receiving, identifying, or classifying notices of events requiring an immediate response.
- b. Establishing or maintaining communication with fire, police, or other public officials.
- c. Prompt and effective response to a notice of each type of gas emergency.
- d. Availability of personnel, equipment, tools, or materials as needed at the emergency scene.
- e. Actions to protect people first.
- f. Emergency shutdown and pressure reduction in any section of the system.
- g. Making safe any actual or potential hazard to life or property.
- h. Notifying appropriate fire, police, or other public officials of gas pipeline emergencies and coordinating both planned and actual responses during an emergency.
- i. Safely restoring service outages.
- j. Beginning investigative action as soon as possible after the emergency.

Requirement: 49 CFR 192.615(a)

Summary for 'vio_class' = R (10 detail records)

Sum

80 0 80

Summary for 'vio_gl' = G (31 detail records)

Sum

137 0 137

Gas/Liquid Violation: Hazardous Liquid: 49 CFR Part 195

Violation Type: Inspection or test not performed

viol_cod	viol_text	vio_r	vio_n	vio_occ
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.	3	24	27

Requirement: 49 CFR 195.412(a)

416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	1	24	25
420502	The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. Requirement: 49 CFR 195.420(b)	1	16	17
428501	The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.428(a)	2	14	16
786502	The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. Requirement: 16 TAC 7.86(1)	0	14	14
432501	The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.432	2	10	12
416503	The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months. Requirement: 49 CFR 195.416(c)	0	10	10
418504	The pipeline(s) at the listed location(s) was not monitored twice each calendar year, with intervals not exceeding seven and one-half months, to determine the effectiveness of the inhibitors or the degree of internal corrosion. Requirement: 49 CFR 195.418(c)	0	4	4
786509	The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months. Requirement: 16 TAC 7.86(5)(A)	0	2	2
786511	The listed interference bond was not electrically checked for performance once each calendar year with intervals not exceeding 15 months Requirement: 16 TAC 7.86(5)(B)	0	1	1
401501	The pipeline segment(s) at the listed location(s) was not operated and maintained as required. Requirement: 49 CFR 195.401(a)	1	0	1

Summary for 'vio_class' = 1 (11 detail records)

Sum	10	119	129
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Violation Type: Physical deficiency of the pipeline facility

viol_cod	viol_text	vio_r	vio_n	vio_occ
786508	The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: Requirement: 16 TAC 7.86(4)(B)	6	29	35
410503	The aboveground pipeline(s) listed below did not have line markers. Requirement: 49 CFR 195.410(c)	2	8	10
005504	The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E. Requirement: 49 CFR 195.5(a)(4)	0	10	10
242501	Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected. Requirement: 49 CFR 195.242(a)	0	9	9
420503	The listed valve(s) was not protected from unauthorized operation and/or vandalism. Requirement: 49 CFR 195.420(c)	1	6	7
410501	Line markers were not placed or maintained over the following buried pipeline(s). Requirement: 49 CFR 195.410(a)(1)	2	4	6
786501	The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating. Requirement: 16 TAC 7.86(1)	1	4	5

410502	Line markers were inadequate because of the following reason(s):	0	4	4
	a. They did not have the words "Warning" followed by "Petroleum (or name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline."			
	b. The letters were not at least one-inch high with one-quarter inch stroke.			
	c. The background color did not contrast sharply with the lettering.			
	d. They did not have the operator's name.			
	e. They did not have the operator's 24-hour telephone number.			
	f. They did not have the operator's 24-hour telephone area code.			
	Requirement: 49 CFR 195.410(a)(2)			
786514	Prompt remedial action was not taken to correct cathodic protection deficiencies found at the listed location(s):	1	1	2
	Requirement: 16 TAC 7.86(6)			
244501	Test leads on the listed pipeline(s) were not installed at intervals frequent enough to ensure adequate cathodic protection.	2	0	2
	Requirement: 49 CFR 195.244(a)			
258501	The valve(s) at the following location(s) was not protected from tampering.	0	1	1
	Requirement: 49 CFR 195.258(a)			
785501	The pipeline listed below was not constructed of steel and had not been granted a special exception by the Railroad Commission.	0	1	1
	Requirement: 16 TAC 7.85			
416508	The pipeline(s) at the following location(s) was exposed to the atmosphere and had not been protected from atmospheric corrosion with a proper coating.	1	0	1
	Requirement: 49 CFR 195.416(h)			
406507	Overpressure controls and protective equipment were not adequate on the listed pipeline(s).	1	0	1
	Requirement: 49 CFR 195.406(b)			

416507	The line segment(s) was not repaired or replaced at the listed location(s) where localized corrosion pitting existed to a degree that leakage could occur.	0	1	1
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Requirement: 49 CFR 195.416(g)

416502	Test leads at the following location(s) were not maintained so that the cathodic protection's adequacy could be determined.	0	1	1
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Requirement: 49 CFR 195.416(b)

Summary for 'vio_class' = P (16 detail records)

Sum	17	79	96
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Violation Type: Record, procedure or program not established or maintained

viol_cod	viol_text	vio_r	vio_n	vio_occ
442503	<p>The written damage prevention program was insufficient in the following areas:</p> <p>a. Records of excavation - related persons were not maintained or were not current.</p> <p>b. Procedures for notification to the public of the program and its purpose were not available or were not followed.</p> <p>c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.</p> <p>d. Procedures for documentation of planned excavation activities were not available or were not followed.</p> <p>e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.</p> <p>f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.</p> <p>Requirement: 49 CFR 195.442(b)</p>	1	22	23
404510	<p>Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.</p> <p>Requirement: 49 CFR 195.404(c)(3)</p>	0	14	14
440501	<p>A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.</p> <p>Requirement: 49 CFR 195.440</p>	0	13	13

784514	Records of hydrostatic testing of the pipeline and/or components were not maintained.	0	10	10
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Requirement: 16 TAC 7.84(e)(3)

266506	A complete record was not maintained on the location of:	0	4	4
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a. each valve

b. each corrosion test station

Requirement: 49 CFR 195.266(f)

404504	The maps and records of the pipeline system did not include the maximum operating pressure of each pipeline.	0	1	1
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Requirement: 49 CFR 195.404(a)(3)

Summary for 'vio_class' = R (6 detail records)

Sum		1	64	65
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Summary for 'vio_gl' = L (33 detail records)

Sum		28	262	290
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Grand Total		165	262	427
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G

RRCII 02324

Violation Listings

RRCII 02325

Violations: Interstate

KOCH GATEWAY PIPELINE COMPANY

KOCH GATEWAY/CARTHAGE

ID and Name: 831234 TPL-059 CARTHAGE

Jur: O Reg: R

code	text	notes
179005	The blowdown discharge at the following location was not located so that the gas could be blown to the atmosphere without undue hazard. Requirement: 49 CFR 192.179(c)	A. Town Border Station of Tenaha, Texas B. Blow off valve for TPL 59-6
323004	Casing used for the pipeline under a railroad or highway at the following location(s) had vents not protected from the weather to prevent water from entering the casing. Requirement: 49 CFR 192.323(d)	There was no casing vent on Line 059-06
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations. Requirement: 49 CFR 192.463(a)	Main line valve at Mile Post 86.50 -730 mv
479001	The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating. Requirement: 49 CFR 192.479(a)	Main line valve at Mile Post 87.71
479004	Atmospheric corrosion was found on the exposed aboveground pipe at the listed location(s), and remedial measures were not taken to the extent required by 49 CFR 192.485, 192.487, or 192.489. Requirement: 49 CFR 192.479(b)(2)	Line 059: Block Valve Station No. 1426+80

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RRCII 02326

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

705001 There was no patrol program to observe surface conditions on and adjacent to the transmission line right-of-way.

Effective patrolling no longer possible due to vegetation.

Requirement: 49 CFR 192.705(a)

707100 Line markers on mains or transmission lines were inadequate because of the following reason(s):

They did not have the operator's name and/or 24 hour telephone number and area code.

Requirement: 49 CFR 192.707(d)

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RRCII 02327

743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Station inspection records did not indicate capacities are being verified.

Requirement: 49 CFR 192.743(b)

ID and Name: 831235 TPL-63 CARTHAGE

jur: O req: R

code	text	notes
179005	The blowdown discharge at the following location was not located so that the gas could be blown to the atmosphere without undue hazard.	TPL-063 main line valve at MP 139.6
	Requirement: 49 CFR 192.179(c)	
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations.	A. Mile 159, Pole 2, Brumble T1 -.816v B. Arkla Pole 5 MP 156.14 -.542v C. Mile 149, Pole 5 MP 149.15 -.572v D. ML B/O past Tiller A-2 MP 1.57 -.742v E. End TPL-63I MP 4.98 -.623v
	Requirement: 49 CFR 192.463(a)	
479003	Aboveground pipeline was exposed to the atmosphere at the following site(s), but areas of atmospheric corrosion had not been determined.	Intersection of TPL-063 and TPL-266
	Requirement: 49 CFR 192.479(b)(1)	
603200	Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below: a. Inspection /Monitoring Pressure Regulating Station b. Inspection/Monitoring Overpressure Protection Equipment	Location: Hanson Switch 4"
	Requirement: 49 CFR 192.603(b)	

- 614002 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

- 707002 Line markers were not placed or maintained along the following publicly accessible, above ground main or transmission line.

Intersection of TPL-063 and TPL-266

Requirement: 49 CFR 192.707(c)

- 743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Station inspection records did not indicate capacities are being verified.

Requirement: 49 CFR 192.743(b)

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RRCII 02329

ID and Name: 831236 TPL-92 CARTHAGE

jur: O reg: R

code	text	notes
479001	The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating. Requirement: 49 CFR 192.479(a)	TPL-92 at City of Joaquin tap. Relief valve stack not coated to prevent atmospheric corrosion.
614002	The written damage prevention program was insufficient in the following areas: a. Records of excavation - related persons were not maintained or were not current. b. Procedures for notification to the public of the program and its purpose were not available or were not followed. c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed. Requirement: 49 CFR 192.614(b)	
615012	A liaison had not been established and/or maintained with appropriate fire, police and other public officials. Requirement: 49 CFR 192.615(c) A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.	
616001	There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency. Requirement: 49 CFR 192.616	

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RRCII 02330

743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Station inspection records did not indicate capacities are being verified.

Requirement: 49 CFR 192.743(b)

ID and Name: 831237 T-266 CARTHAGE TO STERLINGTON

Jur: O req: R

code	text	notes
199006	The pressure relief or limiting device(s) at the location(s) below had discharge stacks, vents, or outlet ports that were not designed or installed to discharge gas into the atmosphere without undue hazard.	Location: Carthage Compressor Station Dischare stacks are too low. Should extend above a person's head.

Requirement: 49 CFR 192.199(e)

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

707100 Line markers on mains or transmission lines were inadequate because of the following reason(s):

They did not have the operator's name and/or 24 hour telephone number and area code.

At the following locations:

- A. Sabine River Crossing
- B. Exposed pipe at intersection of Line 063.

Requirement: 49 CFR 192.707(d)

743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Station inspection records did not indicate capacities are being verified.

Requirement: 49 CFR 192.743(b)

ID and Name: 831238 391-02-01 CARTHAGE

jur: O reg: R

code	text	notes
179005	The blowdown discharge at the following location was not located so that the gas could be blown to the atmosphere without undue hazard.	First valve station west of Carthage Compressor Station.
Requirement: 49 CFR 192.179(c)		
199006	The pressure relief or limiting device(s) at the location(s) below had discharge stacks, vents, or outlet ports that were not designed or installed to discharge gas into the atmosphere without undue hazard.	Location: Carthage Compressor Station. Discharge stacks are too low. Should extend above a person's head.
Requirement: 49 CFR 192.199(e)		

317003	The aboveground transmission line(s) or main(s) at the location(s) below was/were not protected from accidental damage by vehicular traffic or other similar causes.	<p>A. Aboveground 1-inch tap line to Entex Rural Station located behind UPRC Compressor Station west of Carthage. This line is in the middle of the right-of way with a weak broken barricade. MAOP: 800 psig.</p> <p>B. Lacy Plant Tie-in</p> <p>C. Beckville Tap aboveground piping is located in hay meadow. Needs barricade.</p>
Requirement: 49 CFR 192.317(b)		
323004	Casing used for the pipeline under a railroad or highway at the following location(s) had vents not protected from the weather to prevent water from entering the casing.	Casing vent at CR 150 crossing broken. Not connected to casing.
Requirement: 49 CFR 192.323(d)		
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations.	Lacy Plant Tie-in Below-.850v
Requirement: 49 CFR 192.463(a)		
479001	The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating.	Aboveground pipe at Beckville Tap
Requirement: 49 CFR 192.479(a)		
479004	Atmospheric corrosion was found on the exposed aboveground pipe at the listed location(s), and remedial measures were not taken to the extent required by 49 CFR 192.485, 192.487, or 192.489.	<p>A. First valve station west of Carthage Compressor Station.</p> <p>B. Block valve station at LSG Tap.</p> <p>C. Lacy Plant Tie-in</p>
Requirement: 49 CFR 192.479(b)(2)		

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

707002 Line markers were not placed or maintained along the following publicly accessible, above ground main or transmission line.

Requirement: 49 CFR 192.707(c)

- A. First valve station west of Carthage Compressor Station.
 - B. Tap line to Entex Rural Station
 - C. Beckville Tap
 - D. Lacy Plant Tie-in
-

743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Requirement: 49 CFR 192.743(b)

Station inspection records did not indicate capacities are being verified.

745001 The listed transmission line valve(s) that might be required during an emergency was not inspected and partially operated at the prescribed interval.

Blowdown valves and hammer-lock caps have not been serviced as required.

Requirement: 49 CFR 192.745

ID and Name: 831302 TPL-264 CARTHAGE

Jur: O reg: R

code	text	notes
603300	Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below: Valve Inspection Records. Requirement: 49 CFR 192.603(b)	Valve Inspection Records for Valves No. 36 and No. 132
614002	The written damage prevention program was insufficient in the following areas: a. Records of excavation - related persons were not maintained or were not current. b. Procedures for notification to the public of the program and its purpose were not available or were not followed. c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed. Requirement: 49 CFR 192.614(b)	
615012	A liaison had not been established and/or maintained with appropriate fire, police and other public officials. Requirement: 49 CFR 192.615(c) A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.	

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831303 TPL-265 CARTHAGE

Jur: O reg: R

code	text	notes
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603100	Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:	
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- a. Patrolling Records.
- b. Valve Inspection Records.
- c. Atmospheric Corrosion Records

Requirement: 49 CFR 192.603(b)

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831304 TPL-213 CARTHAGE

jur: O req: R

code	text	notes
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations.	B. Block Valve No. 24 -821 mv
Requirement: 49 CFR 192.463(a)		

- 614002 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

- 743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Requirement: 49 CFR 192.743(b)

ID and Name: 831305 TPL-263 CARTHAGE

jur: O reg: R

code	text	notes
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- 614002 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

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- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

- 743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Requirement: 49 CFR 192.743(b)

ID and Name: 831306 TPL-212 CARTHAGE

Jur: O req: R

code	text	notes
614002	<p>The written damage prevention program was insufficient in the following areas:</p> <p>a. Records of excavation - related persons were not maintained or were not current.</p> <p>b. Procedures for notification to the public of the program and its purpose were not available or were not followed.</p> <p>c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.</p>	

Requirement: 49 CFR 192.614(b)

615002 The written emergency plan did not include procedures for ~~the~~ following item(s):

- a. Receiving, identifying, or classifying notices of events requiring an immediate response.
- b. Establishing or maintaining communication with fire, police, or other public officials.
- c. Prompt and effective response to a notice of each type of gas emergency.
- d. Availability of personnel, equipment, tools, or materials as needed at the emergency scene.
- e. Actions to protect people first.
- f. Emergency shutdown and pressure reduction in any section of the system.
- g. Making safe any actual or potential hazard to life or property.
- h. Notifying appropriate fire, police, or other public officials of gas pipeline emergencies and coordinating both planned and actual responses during an emergency.
- i. Safely restoring service outages.
- j. Beginning investigative action as soon as possible after the emergency.

Requirement: 49 CFR 192.615(a)

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831307 TPL-173 CARTHAGE

jur: O req: R

code text notes

603100 Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:

- a. Patrolling Records.
- b. Valve Inspection Records.
- c. Atmospheric Corrosion Records

Requirement: 49 CFR 192.603(b)

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831308 TPL-86 CARTHAGE

jur: O req: R

code	text	notes
614002	<p>The written damage prevention program was insufficient in the following areas:</p> <p>a. Records of excavation - related persons were not maintained or were not current.</p> <p>b. Procedures for notification to the public of the program and its purpose were not available or were not followed.</p> <p>c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.</p> <p>Requirement: 49 CFR 192.614(b)</p>	
615012	<p>A liaison had not been established and/or maintained with appropriate fire, police and other public officials.</p> <p>Requirement: 49 CFR 192.615(c)</p> <p>A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.</p>	
616001	<p>There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.</p> <p>Requirement: 49 CFR 192.616</p>	

ID and Name: 831309 TPL 66-CARTHAGE

jur: O req: R

code	text	notes
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RRCII 02342

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831310 TPL-65 CARTHAGE

jur: O req: R

code text

notes

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RRCII 02343

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

KOCH GATEWAY/LONGVIEW

ID and Name: 831349 TPL-391 LONGVIEW

jur: O req: R

code	text	notes
179005	The blowdown discharge at the following location was not located so that the gas could be blown to the atmosphere without undue hazard.	Blowdown valves were installed in residential yards in the Fall of 1997. Stacks are short enough to pose a potential problem due to their proximity to houses and power lines.

Requirement: 49 CFR 192.179(c)

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RRCII 02344

463001 The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations.

TPL-391-4(Tatum Lateral) - @ Tatum CG - .601

Requirement: 49 CFR 192.463(a)

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831350 TPL-10 LONGVIEW

Jur: O reg: R

code text

notes

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RRCII 02345

491005 There were no records, or records were insufficient, for the listed corrosion control tests, surveys, or inspections.

Requirement: 49 CFR 192.491(b)(2)

EPU 1972 Inspection for May, 1997. No data was filled out on the inspection report for this rectifier in May, 1997.

603300 Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:

Valve Inspection Records.

Requirement: 49 CFR 192.603(b)

No records were available for 1997 block valve inspections of BV 1183; BV 1184; BV 1185; and BV 774. Records for 1995 and 1997 block valve inspections of 870, 871, and 872 indicated they were not inspected on the scheduled date due to high water, but would be when the water went down. No records were available to demonstrate that the inspection had been done later.

614002 The written damage prevention program was insufficient in the following areas:

a. Records of excavation - related persons were not maintained or were not current.

b. Procedures for notification to the public of the program and its purpose were not available or were not followed.

c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831351 TPL-65-2 LONGVIEW

Jur: O Reg: R

code	text	notes
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614002	<p>The written damage prevention program was insufficient in the following areas:</p> <p>a. Records of excavation - related persons were not maintained or were not current.</p> <p>b. Procedures for notification to the public of the program and its purpose were not available or were not followed.</p> <p>c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.</p>	
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Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831352 TPL-430 LONGVIEW

Jur: O Reg: R

code	text	notes
199006	The pressure relief or limiting device(s) at the location(s) below had discharge stacks, vents, or outlet ports that were not designed or installed to discharge gas into the atmosphere without undue hazard. Requirement: 49 CFR 192.199(e)	Regulator Station at tap for TPL-430-1. Regulator vents were repositioned in the course of this evaluation; therefore, no further response is required.
199009	The pressure relief or limiting device(s) at the location(s) below was not designed to prevent an unauthorized person from operating any stop valve that would make the device inoperable. Requirement: 49 CFR 192.199(h)	Regulator at Noram Delivery. The control line to the regulator had an unprotected needle valve which if closed would render the regulator ineffective.
199010	The valve located in the regulator station bypass at the listed location(s) was not designed to prevent unauthorized operation that could make the pressure regulating or limiting device ineffective. Requirement: 49 CFR 192.199(h)	Noram Delivery.
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations. Requirement: 49 CFR 192.463(a)	TPL-430-1 @ MP 1.47 (Entex EOL) .542v

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RRCII 02348

465006 Prompt remedial action was not taken to correct cathodic protection deficiencies found at the listed location(s):

Requirement: 49 CFR 192.465(d)

a. TPL 430-1 @ MP 0.1 (CR 1105)
Reading 7-3-96: -.795v
Reading 7-10-97: -.651v

b. TPL 430-1 @ MP 0.36 (I-20 NS)
Reading 7-3-96: -.639v
Reading 7-10-97: -.654v

c. TPL 430-1 @ MP 1.47 (Entex EOL)
Reading 7-3-96: -.520v
Reading 7-10-97: -.542v

d. TPL 430-2 @ MP 0.81 (Farm Tap)
Reading 7-3-96: -.604v
Reading 7-11-97: -.601v

e. TPL 430-2 @ MP 3.11 (NS Highway 80)
Reading 7-3-96: -.793v
Reading 7-11-97: -.791v

f. TPL 430-2 @ MP 3.34 (Entex EOL)
Reading 7-3-96: -.867v
Reading 7-11-97: -.821v

603400 Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:

A. Road and Railroad Patrol Records

B. Leak Survey Records

Requirement: 49 CFR 192.603(b)

Road and Railroad Patrol Records could not be located for inspections of TPL 430; TPL 430-1; TPL 430-2; TPL 430-3; and TPL 430-4 in the second half of 1997. Leak Survey Records were not located for Class 3 areas of TPL 430-3 and TPL 430-4 in the second half of 1997.

614002 The written damage prevention program was insufficient in the following areas:

a. Records of excavation - related persons were not maintained or were not current.

b. Procedures for notification to the public of the program and its purpose were not available or were not followed.

c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831353 TPL-11 LONGVIEW

jur: O req: R

code	text	notes
161005	The support(s) or anchor(s) on the exposed pipeline listed below was/were not made of durable, noncombustible material. Requirement: 49 CFR 192.161(c)	Meter tube @ TPL-11 to TPL-70-14 Tie-Over. Meter tube was supported by wooden skids. Proper noncombustible supports were installed in the course of the inspection; therefore, no further response is required.
179002	Operating devices for sectionalizing block valves were not readily accessible or were not protected from tampering and damage. Requirement: 49 CFR 192.179(b)(1)	Block Valve 672 and 673 at TPL-11-6-3 tie-in had chains and locks wrapped around the valve body, but nothing to protect the operating stem from unauthorized operation.
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations. Requirement: 49 CFR 192.463(a)	A. TPL-11 @ mp 40.64 (20' west of BV) - .432v B. TPL-11-2 @ mp 9.02 (S. Henderson Field Tap) -.823v C. TPL-11-2 @ MP 9.94 (Farm Tap West of FM 2276) -.728v

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RRCH 02350

465006 Prompt remedial action was not taken to correct cathodic protection deficiencies found at the listed location(s):

Requirement: 49 CFR 192.465(d)

a. TPL-11 @ MP 16.05 (Farm Tap)
Reading 7-29-96: -.707v
Reading 9-25-97: -.510v

b. TPL-11 @ MP 22.24 (McMurrey Pump Station)
Reading 4-10-96: -.625v
Reading 5-14-97: -.611v

c. TPL-11 @ MP 34.82 (Farm Tap)
Reading 4-18-96: -.765v
Reading 6-16-97: -.680v

d. TPL-11 @ MP 37.00 (TL @ Marker)
Reading 4-18-96: -.700v
Reading 6-17-97: -.675v

e. TPL-11 @ MP 55.00 (Blow off)
Reading 4-26-96: -.535v
Reading 5-23-97: -.547v

All potentials noted have been corrected to at least -.85v.

603500 Records necessary to administer the operation and maintenance plan were not maintained or were inadequate in the areas listed below:

Road and Railroad Crossing Patrol Records

Requirement: 49 CFR 192.603(b)

Could not locate patrol records for TPL-11 Class 3 area inspections dated April, 1997. Could not locate patrol records for Class 3 areas of TPL-11-6 and TPL-11-6-3 for October, 1997, inspection.

614002 The written damage prevention program was insufficient in the following areas:

a. Records of excavation - related persons were not maintained or were not current.

b. Procedures for notification to the public of the program and its purpose were not available or were not followed.

c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

- 739001 The following pressure limiting station(s), relief device(s), pressure regulator station(s) or equipment was not inspected and tested at the specified interval to determine if it was:

RV station 1-20-29-008-0 on TPL-11-2. Inspection exceeded the 15-month maximum frequency for inspections conducted on 4-2-95 and then on 11-19-96.

- a. In good mechanical condition.
- b. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed.
- c. Set to function at the correct pressure.
- d. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Requirement: 49 CFR 192.739

- 743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Records do not demonstrate that the required capacity review was conducted during the 10-31-95 inspection of the Regulator/Relief Valve Station on TPL-11-2-2.

Requirement: 49 CFR 192.743(b)

ID and Name: 831354 TPL-8 LONGVIEW

Jur: O req: R

code text

notes

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RRCH 02352

- 463001 The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations.
- TPL-8-16 MP 7.43 (Farm Tap Steele Road) - .800v Pipe-to-Soil Potential was brought up to -.910v during the evaluation; therefore, no further response is required.

Requirement: 49 CFR 192.463(a)

- 465001 The cathodic protection system at the listed location(s) has not been monitored at least once each calendar year, within intervals not exceeding 15 months.
- a. TPL-8-18 b. TPL-8-18-5 TPL-8-18 was surveyed 2-14-96 and then 6-4-97. TPL-8-18-5 was surveyed 2-16-96 and then 6-12-97.

Requirement: 49 CFR 192.465(a)

- 465006 Prompt remedial action was not taken to correct cathodic protection deficiencies found at the listed location(s):
- Requirement: 49 CFR 192.465(d)
- a. TPL-8-16 MP 5.00(Entex Petrolite)
Reading 11-18-96: -.705v
Reading 9-13-97: -.580v
- b. TPL-8-16 MP 7.43 (Farm Tap Steele Road)
Reading 10-14-96: -.830v
Reading 9-14-97: -.750v
- c. TPL-5-18 MP 4.50 (Tyler CG #5 Tap)
Reading 2-19-96: -.735v
Reading 6-5-97: -.189v
- Potential at TPL-8-18 MP 4.50 now reads - 1.936v
Potential at TPL-8-16 MP 7.43 now reads - .910v

- 614002 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

- 705002 Patrols on the transmission line right-of-way were not conducted within the specified intervals.

Patrols exceeded 4 1/2 months on Class 3 area from Green Street to highway 42 on TPL-8. Inspected 10-2-96 and then 3-4-97.

Requirement: 49 CFR 192.705(b)

- 743002 Required operating capacities of pressure relief devices at each regulator station were not compared with rated or experimental capacity at least once each calendar year, but at intervals not exceeding fifteen (15) months.

Laird Hill Regulator Station (TPL-8-16-2) and Palestine-Longview/Tyler (TPL-8-16, Station 21-20-08-007) relief capacities not reviewed.

Requirement: 49 CFR 192.743(b)

ID and Name: 831355 TPL-178 LONGVIEW

Jur: O req: R

code	text	notes
463001	The level of cathodic protection for the pipe system(s) listed below did not meet one or more of the criteria specified in Appendix D, Code of Federal Regulations.	Bullard end of TPL-178 -.840v
	Requirement: 49 CFR 192.463(a)	

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

ID and Name: 831356 TPL-1 LONGVIEW

jur: O req: R

code text

notes

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RRCII 02355

465006 Prompt remedial action was not taken to correct cathodic protection deficiencies found at the listed location(s):

Requirement: 49 CFR 192.465(d)

Locations:

A. TPL-1 @MP 22.28 (FM 3251)
 Reading 4-24-96 -.675v
 Reading 5-29-97 -.600v
 B. TPL-1@MP 48.76 (Farm Tap)
 Reading 4-24-96 -.740v
 Reading 5-26-97 -.709v
 C. TPL-1@MP51.59 (Gladewater CG)
 Reading 4-25-96 -.726v
 Reading 5-28-97 -.724v
 D. TPL-1@MP51.80(Farm Tap)
 Reading 4-25-96 -.816v
 Reading 5-28-97 -.527v
 E. TPL-1@MP52.05(Farm Tap)
 Reading 4-25-96 -.422v
 Reading 5-28-97 -.411v
 F. TPL-1@MP52.50(Farm Tap)
 Reading 4-25-96 -.587v
 Reading 5-28-97 -.521v
 G. TPL-1@MP52.55(Blowoff)
 Reading 4-25-96 -.645v
 Reading 5-28-97 -.447v
 H. TPL-1@MP56.66(Farm Tap)
 Reading 4-25-96 -.836v
 Reading 5-29-97 -.555v
 I. TPL-1@MP 97.57 (Tap TPL 1-27)
 Reading 3-25-97 -.610v
 Reading 4-30-97 -.645v
 J. TPL-1@MP 101.47 (VZ 1913)
 Reading 3-25-96 -.775v
 Reading 5-6-97 -.824v
 K. TPL-1@MP107.85A(Tap TPL 1-25)
 Reading 4-19-96 -.700v
 Reading 5-19-97 -.700v
 L. TPL-1@MP 116.09(West of FM 47)
 Reading 4-30-96 -.450v
 Reading 4-20-97 -.600v
 M. TPL-1@MP119.48(MID@Pole)
 Reading 5-13-96 -.823v
 Reading 4-12-97 -.627v
 N. TPL-1@MP130.76(SECO Crane)
 Reading 5-7-96 -.624v
 Reading 4-30-97 -.577v
 O. TPL-1@MP 183.95 (Randoll Mill Rd. Nursery)
 Reading 6-28-96 -.826v
 Reading 6-29-97 -.825v
 P. TPL-1@MP 185.39 (Randoll Mill Rd.)
 Reading 6-28-96 -.698v
 Reading 6-29-97 -.794v
 Q. TPL-1-27@MP 0.0 (No description)
 Reading 3-25-96 -.721v
 Reading 3-27-97 -.823v
 R. TPL-1-27@ MP 0.25 (No description)
 Reading 3-25-96 -.704v
 Reading 3-27-97 -.841v

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RRCH 02356

S. TPL-1-31@MP 0.25 (Cooks RD FT)
Reading 7-3-96 -.715v
Reading 6-26-97 -.826v
T. TPL-1-31@MP 2.50 (Meadow Brook Dr)
Reading 7-7-96 -.785v
Reading 6-26-97 -.642v

All test locations listed above are currently at
or above the 0.85 v requirement.

- 479001 The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating.

Replaced creek crossing at MP 182.28 (Park Hill St.) Debris from creek flow had chipped away coating.

Requirement: 49 CFR 192.479(a)

- 614002 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

705002 Patrols on the transmission line right-of-way were not conducted within the specified intervals.

Road and railroad patrols exceeded 4-1/2 month maximum frequency on TPL-1-31 Class 3 areas between 3-4-97 and 8-10-97.

Requirement: 49 CFR 192.705(b)

739001 The following pressure limiting station(s), relief device(s), pressure regulator station(s) or equipment was not inspected and tested at the specified interval to determine if it was:

Regulator Station inspection exceeded the 15-month maximum frequency requirement.
Location: Mineola City Gate #1 (21-20-01-062) for period 12-31-96 to 8-29-95.

a. In good mechanical condition.

b. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed.

c. Set to function at the correct pressure.

d. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Requirement: 49 CFR 192.739

745001 The listed transmission line valve(s) that might be required during an emergency was not inspected and partially operated at the prescribed interval.

Requirement: 49 CFR 192.745

No record of inspection for BV 99304 and BV 99303 in 1997. Inspections exceeded 15 months for block valves between 2-12-96 and 8-14-97.

A. TPL-1 BV's: 175; 50263; 854; 852; 164; 990351; 186; 187; 190; 50396; 50397; 855; 851; 990644; 184; 185; 188; 189; 191; 198; 861; 859; 857; 862; 860; 856.

B. TPL-1-31 BV'S: 193; 194; 195; 196; 197. (2-12-96 to 8-21-97)

Operator indicated that valves had been inspected in early 1997 and then again in August, 1997, to facilitate changing the time of year the inspection is done. No records could be located however.

ID and Name: 831357 TPL-6 LONGVIEW

jur: O reg: R

code text

notes

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RRCH 02358

- 614002 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

- 615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

- 616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

- 705002 Patrols on the transmission line right-of-way were not conducted within the specified intervals.

Road and railroad patrols exceeded the 4 1/2-month maximum for Class 3 areas between the 3-13-97 and 8-10-97 inspections.

Requirement: 49 CFR 192.705(b)

ID and Name: 831358 TPL-4-LONGVIEW

Jur: O reg: R

code text

notes

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RRCII 02359

614002 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

Requirement: 49 CFR 192.614(b)

615012 A liaison had not been established and/or maintained with appropriate fire, police and other public officials.

Requirement: 49 CFR 192.615(c)

A pipeline operator must meet face-to-face with appropriate public officials, biennially at a minimum. Documentation of mutual understanding is required. Maintenance of liaison requires meeting with officials as often as necessary and current (annual) documentation of the mutual understanding.

616001 There was no continuing education program to teach customers, the public, government organizations, or those engaged in excavation related activities how to recognize and report a gas pipeline emergency.

Requirement: 49 CFR 192.616

745001 The listed transmission line valve(s) that might be required during an emergency was not inspected and partially operated at the prescribed interval.

Requirement: 49 CFR 192.745

- A. BV 203
- B. BV 204
- C. BV 206

Inspection exceeded the 15-month maximum frequency for the period 1-22-96 to 8-11-97. Operator indicated that the valves were inspected in early 1997 and then again in August, 1997, to change the time of year of the inspection. Records could not be located however.

KOCH PIPELINE CO., L.P.

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RRCII 02360

KOCH PL / MEDFORD

ID and Name: 851311 STERLING II

jur: O reg: R

code	text	notes
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year. Requirement: 49 CFR 195.412(a)	Location: U. S. Hwy 90 MP 530-051 Vegetation overgrowth along the pipeline R-O-W was to the extent that adequate aerial surveillance's could not have been performed.
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Location: U.S. Hwy 80 & U.P. RR casing
786508	The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: Requirement: 16 TAC 7.86(4)(B)	Location: Odel Station A. Diamond Shamrock 8" Tie-in-821 mv B. Diamond Shamrock 12" Tie-in-828mv C. Warren Tie-in 6' -828mv

ID and Name: 851359 MCCAMEY

jur: O reg: R

code	text	notes
410503	The aboveground pipeline(s) listed below did not have line markers. Requirement: 49 CFR 195.410(c)	Brazos River valve
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year. Requirement: 49 CFR 195.412(a)	A. Hwy. 158 B. Brazos River Records indicated inspections are being performed at scheduled intervals by air patrol. It appears that effective patrolling along some sections of this pipeline cannot be accomplished because of heavy growth of underbrush and trees.
432501	The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.432	Haskell Station

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RRCH 02361

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

A. FM 1720, M.P. 474+58 -.647 V

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851360 TEXAS FERC

Jur: O reg: R

code text

notes

000000 No violations

KOCH PL / MIDLAND

ID and Name: 851346 CHAPARRAL PIPELINE

Jur: O reg: R

code text

notes

406507 Overpressure controls and protective equipment were not adequate on the listed pipeline(s).

Overpressure controls were set above the MOP for the Chaparral system.

Requirement: 49 CFR 195.406(b)

420502 The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly.

A. Valve No. 16
B. Valve No. 17
C. Valve No. 18
D. Valve No. 19

Requirement: 49 CFR 195.420(b)

420503 The listed valve(s) was not protected from unauthorized operation and/or vandalism.

Main line valve. This was corrected during the safety evaluation.

Requirement: 49 CFR 195.420(c)

428501 The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months.

No inspection of the pressure control equipment where the operator is receiving the product at Mount Belview.

Requirement: 49 CFR 195.428(a)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

A. M.P. 378.325 -.765v
B. M.P. 74.046 -.705v
C. M.P. 81.595 -.813v

Requirement: 16 TAC 7.86(4)(B)

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RRCII 02362

786514 Prompt remedial action was not taken to correct
cathodic protection deficiencies found at the listed
location(s):

Station No. 378.325

Requirement: 16 TAC 7.86(6)

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RRCII 02363

Violations: Intrastate

KOCH HYDROCARBON COMPANY

KOCH HYDROCARBON/MIDLAND

ID and Name: 250711 NGL/SONORA TO ROBERT RANCH

jur: I req: R

code text notes

000000 No violations

KOCH PIPELINE CO., L.P.

HAZARDOUS LIQUID SYSTEMS/CORPUS

ID and Name: 752125 FALLS CITY STATION TO PETTUS 6"

jur: I req: R

code text notes

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Requirement: 16 TAC 7.86(4)(B)

Weigang Tap

KOCH PL / CORPUS CHRISTI

ID and Name: 450937 STAR 8"

jur: I req: R

code text notes

000000 No violations

ID and Name: 450938 MARLIN TO TEMPLE 4" (SOUTHWEST PIPELINE)

jur: I req: R

code text notes

000000 No violations

ID and Name: 731687 KRC OXY HYDROGEN 6"/10" PIPELINE

jur: I req: R

code text notes

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RRCII 02364

000000 No violations

ID and Name: 750120 EAST WHITE POINT 10"

Jur: I reg: R

code text

notes

000000 No violations

ID and Name: 750183 KRC 12"

Jur: I reg: R

code text

notes

786501 The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating.

Atmospheric corrosion at transition tape located at West Plant site.

Requirement: 16 TAC 7.86(1)

ID and Name: 750185 VIOLA CRUDE PIPELINE #1

Jur: I reg: R

code text

notes

000000 No violations

ID and Name: 750188 KRC BURNER CARGO

Jur: I reg: R

code text

notes

000000 No violations

ID and Name: 750194 VIOLA 16"

Jur: I reg: R

code text

notes

000000 No violations

ID and Name: 750196 CRUDE/RATTLESNAKE 10"-12"

Jur: I reg: R

code text

notes

000000 No violations

ID and Name: 750199 LAMBERT 10" CRUDE PIPELINE

Jur: I reg: R

code text

notes

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RRCH 02365

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Lambert station

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 750202 PEARSALL-DILLEY 10"

jur: I **req:** R

code **text** **notes**

000000 No violations

ID and Name: 750207 AGUA DULCE 10"

jur: I **req:** R

code **text** **notes**

000000 No violations

ID and Name: 750209 MAYO 10"

jur: I **req:** R

code **text** **notes**

000000 No violations

ID and Name: 750213 VIOLA

jur: I **req:** R

code **text** **notes**

000000 No violations

ID and Name: 751675 KRC OXY PROPANE 4" PIPELINE

jur: I **req:** R

code **text** **notes**

000000 No violations

ID and Name: 751771 KRC EAST 8"

jur: I **req:** R

code **text** **notes**

000000 No violations

ID and Name: 751852 KRC EAST 10"

jur: I **req:** R

code **text** **notes**

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RRCII 02366

410503 The aboveground pipeline(s) listed below did not have line markers.

Location: Lawrence St. Station

Requirement: 49 CFR 195.410(c)

ID and Name: 751920 INGLESIDE JCT. 12"

jur: I req: R

code text

notes

000000 No violations

ID and Name: 752113 BENAVIDES #1 T/I 4"

jur: I req: R

code text

notes

000000 No violations

ID and Name: 752114 CASO CARGO

jur: I req: R

code text

notes

000000 No violations

ID and Name: 752115 8" LPG P/L

jur: I req: R

code text

notes

000000 No violations

ID and Name: 752116 REFUGIO 12" CRUDE PIPELINE

jur: I req: R

code text

notes

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Lambert Station

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 752117 LEOPARD #2

jur: I req: R

code text

notes

000000 No violations

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RRCH 02367

ID and Name: 752118 THREE RIVERS Jur: I reg: R

code text notes

000000 No violations

ID and Name: 752119 MAYO Jur: I reg: R

code text notes

000000 No violations

ID and Name: 752120 KRC 6" & 8" PROPYLENE/PROPANE Jur: I reg: R

code text notes

000000 No violations

KOCH PL / MEDFORD

ID and Name: 650199 EP MIX/CHICO-FARMERSVILLE 4", 6" Jur: I reg: R

code text notes

244501 Test leads on the listed pipeline(s) were not installed at intervals frequent enough to ensure adequate cathodic protection. Location: Between FM 151 (mp 21.92) and MLV (mp 27.83), 5.91 miles.

Requirement: 49 CFR 195.244(a)

416508 The pipeline(s) at the following location(s) was exposed to the atmosphere and had not been protected from atmospheric corrosion with a proper coating. Location: A. FM 1655 MLV mp 8.59
B. FM 377 MLV mp 53.50
C. FM 1385 Tap mp 59.20
D. HWY 75 MLV mp 75.72

Requirement: 49 CFR 195.416(h)

- 442503 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
 - d. Procedures for documentation of planned excavation activities were not available or were not followed.
 - e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
 - f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Location: MP 54.5 Sand Pit (Jan. 1997 leak site)

Note: Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not followed.

Requirement: 49 CFR 195.442(b)

ID and Name: 651440 SOUTHLAKE 12"

Jur: I reg: R

code	text	notes
244501	Test leads on the listed pipeline(s) were not installed at intervals frequent enough to ensure adequate cathodic protection. Requirement: 49 CFR 195.244(a)	Location: Between the intermediate valve site Hwy 121. (4.2 miles)
410501	Line markers were not placed or maintained over the following buried pipeline(s). Requirement: 49 CFR 195.410(a)(1)	Location: Between the intermediate valve site and the valve at Fina. A sufficient number of markers were not placed along the ROW.

ID and Name: 651441 DFW 8"

Jur: I reg: R

code	text	notes
410501	Line markers were not placed or maintained over the following buried pipeline(s). Requirement: 49 CFR 195.410(a)(1)	Location: Between the intermediate valve station and Ogden Terminal A sufficient number of markers were not placed along the Airport Terminals to reflect the pipeline's ROW.

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RRCH 02369

ID and Name: 752126 SQUIR LAKE STA. 8"

jur: I req: R

code text notes

000000 No violations

ID and Name: 752127 ARRIOLA STA NO. 2, 6"

jur: I req: R

code text notes

000000 No violations

KOCH REFINING COMPANY, L.P.

KOCH REF. LP / CORPUS CHRISTI

ID and Name: 451137 TP1-SAN ANTONIO TO AUSTIN

jur: I req: R

code text notes

000000 No violations

ID and Name: 451139 TPL #2-GONZALES TO WACO

jur: I req: R

code text notes

000000 No violations

ID and Name: 451141 TP1-AUSTIN TO WACO

jur: I req: R

code text notes

000000 No violations

ID and Name: 652087 TP11-WACO TO EULESS

jur: I req: R

code text notes

401501 The pipeline segment(s) at the listed location(s)
was not operated and maintained as required.

Requirement: 49 CFR 195.401(a)

Location: 10988 79 Railroad Spur Crossing
Casing to soil potentials reflected a possible
shorted casing
and measures had not been taken to correct
the situation. (-963mv
PS vs -960mv CS).

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RRCH 02370

412501 The surface conditions on or adjacent to the pipeline right-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Requirement: 49 CFR 195.412(a)

Locations:

- A. Valve #408 9430-06
- B. Valve #422 10161-51 Village Crk. MOV
- C. Valve #430 10600-05 Riverside MOV
- D. Valve #442 10808-93 Halten Rd. MOV

Vegetation overgrowth along the pipeline ROW was to the extent that the surface conditions could not be observed during aerial patrols.

428501 The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months.

Requirement: 49 CFR 195.428(a)

Location: Waco Terminal Pressure Controls
Inspections were not conducted within a 15 month period. 7/95-12/96

432501 The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months.

Requirement: 49 CFR 195.432

Location: Fort Worth Terminal break out tanks
Inspections were not conducted within a 15 month period. 6/95-10/96

ID and Name: 751981 TP1-CORPUS TO SAN ANTONIO

jur: I req: R

code text

notes

000000 No violations

ID and Name: 751982 TPL #2 CORPUS TO GONZALES

jur: I req: R

code text

notes

000000 No violations

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RRCH 02371

Violations: Non-Regulated

KOCH PIPELINE CO., L.P.

KOCH PL / CORPUS CHRISTI

ID and Name: 851337 #1 LEE WHEELER TO LA BILLING TO N. TILDEN, 3" jur: I reg: N

code	text	notes
000000	No violations	

ID and Name: 851256 #4 TIE IN 6"-RLC jur: I reg: N

code	text	notes
000000	No violations	

ID and Name: 851341 12" RLC TIE-IN jur: I reg: N

code	text	notes
000000	No violations	

ID and Name: 851279 5800 #1 TO COPANO Y JCT-RLC jur: I reg: N

code	text	notes
000000	No violations	

ID and Name: 851299 5800 #2 T/I RLC jur: I reg: N

code	text	notes
000000	No violations	

ID and Name: 851293 5800 T/I-RLC jur: I reg: N

code	text	notes
000000	No violations	

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RRCII 02372

ID and Name: 851290 B1_RLC

jur: I reg: N

code text notes

000000 No violations

ID and Name: 851296 C PUMP

jur: I reg: N

code text notes

000000 No violations

ID and Name: 851271 C PUMP RLC

jur: I reg: N

code text notes

000000 No violations

ID and Name: 451175 CALDWELL 6"

jur: I reg: N

code text notes

442503 The written damage prevention program was insufficient in the following areas:

a. Records of excavation - related persons were not maintained or were not current.

b. Procedures for notification to the public of the program and its purpose were not available or were not followed.

c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

d. Procedures for documentation of planned excavation activities were not available or were not followed.

e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.

f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

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RRCII 02373

ID and Name: 851280 CLAUDE HEARD RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851248 CLAUDE HEARDE

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851268 COPANO B1 & E3 TO COPANO Y JCT-RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851267 COPANO E2 TO COPANO Y JCT-RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851295 COPANO NORDEN & MORRIS LATERAL RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851244 DEFENSE

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851258 F JCT. RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851316 FALLS CITY STA.

Jur: I reg: N

code text notes

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RRCH 02374

000000 No violations

ID and Name: 851241 FANNIE HEARD

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851288 FANNIE HEARD TO GRETA 4" RHC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851321 GARCIA MAIN GATHERING 4"

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 451178 GERDES TO THREE WAY TRAP

Jur: I reg: N

code text

notes

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Entire pipeline

Requirement: 49 CFR 195.412(a)

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

ID and Name:	851331 GRANT WILLIAMS (A)	jur:	I	req:	N
code	text	notes			
000000	No violations				
<hr/>					
ID and Name:	851335 GRANT WILLIAMS A TO LA BILLINGS TO N. TILDEN	jur:	I	req:	N
code	text	notes			
000000	No violations				
<hr/>					
ID and Name:	851264 GRETA 4"-RHC	jur:	I	req:	N
code	text	notes			
000000	No violations				
<hr/>					
ID and Name:	851298 GRETA 6"-RHC	jur:	I	req:	N
code	text	notes			

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RRCII 02376

000000 No violations

ID and Name: 851291 H&D B JCT.-RLC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851343 HEYSER STA 6"

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851344 HEYSER STA. 4"

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851339 HO TAYLOR TO TILDEN 6"

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851263 HWY 136 4"

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851239 INGELSIDE 8" RHC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851297 JB HEARD 4" RHC

Jur: I reg: N

code text

notes

000000 No violations

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RRCII 02377

ID and Name: 851319 KELSEY 6"

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851250 KOCH PL LP

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851334 LA BILLINGS TO N. TILDEN

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851242 LAKE PASTURE

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851281 LAKE PASTURE 4" LOOP

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851257 LAKE PASTURE 4" LOOP -RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851273 LAKE PASTURE 4" LOOP-RHC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851269 LAMBERT C INJECTION TO LAMBERT 10" RHC

Jur: I reg: N

code text notes

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RRCII 02378

000000 No violations

ID and Name: 851287 LAMBERT H&D O RHC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851249 LAMBERT PEN

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851289 LAMBERT RHC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851247 LAMBERT STA

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851262 LAMBERT STA-RLC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851251 LAMBERT STATION

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851277 LENORE JOSIE TO GRETA 4" RHC

Jur: I reg: N

code text

notes

000000 No violations

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RRCII 02379

ID and Name: 851285 ILAMBERT10 " RHC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851294 MAUDE A L/P RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851282 MAUDE A-RLC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851261 MELON 1 & 2 TO LAMBERT 4" RHC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851259 MELON 1 & 2 TO LAMBERT 8" RHC

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851329 MIRANDO

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 752130 MIRANDO DUVAL MAINLINE 8"

Jur: I reg: N

code text notes

000000 No violations

ID and Name: 851323 MONTE CRISTO GATHERING

Jur: I reg: N

code text notes

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RRCH 02380

000000 No violations

ID and Name: 851328 N. TILDEN 6"

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 851336 N. TILDEN GATHERING 3"

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 851345 N. TILDEN GATHERING 4"

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 851338 N. WHEELER TO TILDEN 6"

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 851243 NEW QUINTANA PUMP STATION

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 451181 NIXON TO PETTUS

Jur: I req: N

code text

notes

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RRCII 02381

- 442503 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
 - d. Procedures for documentation of planned excavation activities were not available or were not followed.
 - e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
 - f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: B/O Tank Pig Trap

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851278 NQ COPANO D TO NQ "Y" RLC, 4"

jur: I req: N

code text notes

000000 No violations

ID and Name: 851286 NQ LAMBERT 10"-RHC

jur: I req: N

code text notes

000000 No violations

ID and Name: 851266 NQ STA 4"-RLC

jur: I req: N

code text notes

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RRCII 02382

000000 No violations

ID and Name: 851245 NQ STA 6

jur: I req: N

code text notes

000000 No violations

ID and Name: 851284 NQ STA. 4" RLC

jur: I req: N

code text notes

000000 No violations

ID and Name: 851246 NQ STATION

jur: I req: N

code text notes

000000 No violations

ID and Name: 851254 NQ STATION 6"

jur: I req: N

code text notes

000000 No violations

ID and Name: 851255 O'CONNER GAS PLANT

jur: I req: N

code text notes

000000 No violations

ID and Name: 851253 O'CONNOR A TO NQ "Y" RLC

jur: I req: N

code text notes

000000 No violations

ID and Name: 851283 O'CONNOR C JCT. RLC, 4"

jur: I req: N

code text notes

000000 No violations

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RRCII 02383

ID and Name: 851270 PENNZOIL C TO NQ - LAMBERT 10" RHC

jur: I req: N

code	text	notes
000000	No violations	

ID and Name: 851314 PETTUS 6"

jur: I req: N

code	text	notes
258501	The valve(s) at the following location(s) was not protected from tampering. Requirement: 49 CFR 195.258(a)	

786508	The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: Requirement: 16 TAC 7.86(4)(B)	Entire system
--------	--	---------------

ID and Name: 851340 PONTIAC 8" PORTILLA LINE

jur: I req: N

code	text	notes
000000	No violations	

ID and Name: 851313 POWERS STA. 8"

jur: I req: N

code	text	notes
786501	The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating. Requirement: 16 TAC 7.86(1)	

ID and Name: 851292 REFUGIO 6"-RLC

jur: I req: N

code	text	notes
000000	No violations	

ID and Name: 851240 REFUGIO 8" RHC

jur: I req: N

code	text	notes

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RRCII 02384

000000 No violations

ID and Name: 851301 REFUGIO B1 TO CITATION ME O'CONNER

jur: I req: N

code text notes

000000 No violations

ID and Name: 851265 REFUGIO EL OSO 4" RLC

jur: I req: N

code text notes

000000 No violations

ID and Name: 851274 REFUGIO N & S TO CITATION ME O'CONNOR

jur: I req: N

code text notes

000000 No violations

ID and Name: 851260 REFUGIO STA. 6" RLC

jur: I req: N

code text notes

000000 No violations

ID and Name: 851300 REFUGIO STA.-RLC

jur: I req: N

code text notes

000000 No violations

ID and Name: 851252 RLC MAIN

jur: I req: N

code text notes

000000 No violations

ID and Name: 451180 ROSAKNY STATION TO NIXON

jur: I req: N

code text notes

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RRCH 02385

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Entire pipeline

Requirement: 49 CFR 195.412(a)

442503 The written damage prevention program was insufficient in the following areas:

Location: CR 154, Gonzales county

a. Records of excavation - related persons were not maintained or were not current.

b. Procedures for notification to the public of the program and its purpose were not available or were not followed.

c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.

d. Procedures for documentation of planned excavation activities were not available or were not followed.

e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.

f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

ID and Name: 851317 SEELIGSON STATION -8"

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 451174 SHAFT TO GERDES

Jur: I req: N

code text

notes

- 442503 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
 - d. Procedures for documentation of planned excavation activities were not available or were not followed.
 - e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
 - f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786501 The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating.

Location: At Gerdes B/O tank

Requirement: 16 TAC 7.86(1)

ID and Name: 451173 SHAFT TO HEARNE STA.

jur: I req: N

code text

notes

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RRCH 02387

442503 The written damage prevention program was insufficient in the following areas:

Location: FM 50

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Heame Station pig receiver

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851324 SHELL-LOPEZ-4"

jur: I req: N

code	text	notes
------	------	-------

000000	No violations	
--------	---------------	--

ID and Name: 851320 SUN FIELD STA.

jur: I req: N

code	text	notes
------	------	-------

000000	No violations	
--------	---------------	--

ID and Name: 752128 SUN FIELD STATION

jur: I req: N

code	text	notes
------	------	-------

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RRCH 02388

000000 No violations

000000 No violations

ID and Name: 851272 TCG 2 TIE IN-RHC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851275 TCGI LEASE 4" RHC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851276 TCGI-RLC

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 851327 THREE RIVERS 6"

Jur: I reg: N

code text

notes

000000 No violations

ID and Name: 451179 THREE WAY TRAP TO ROSANKY STATION

Jur: I reg: N

code text

notes

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Location: Rosanky B/O tank

Requirement: 49 CFR 195.416(a)

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RRCII 02389

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Rosanky B/O tank

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851332 TILDEN 6", 4"

jur: I req: N

code	text	notes
------	------	-------

000000	No violations	
--------	---------------	--

ID and Name: 851330 TILDEN STA.

jur: I req: N

code	text	notes
------	------	-------

000000	No violations	
--------	---------------	--

ID and Name: 752123 TIVOLI 3.5

jur: I req: N

code	text	notes
------	------	-------

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RRCII 02390

000000 No violations

ID and Name: 851342 TIVOLI 6"

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 851333 WC RUTHERFORD 4"

Jur: I req: N

code text

notes

000000 No violations

ID and Name: 851315 WEIGANG GATHERING

Jur: I req: N

code text

notes

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Entire system

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 451176 WEST POINT TO THREE WAY

Jur: I req: N

code text

notes

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RRCII 02391

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

ID and Name:	code	text	notes	jur:	reg:
851318 YUTTERIA 6"				I	N
	000000	No violations			

ID and Name:	code	text	notes	jur:	reg:
851326 YUTTERIA GATHERING				I	N
	000000	No violations			

ID and Name:	code	text	notes	jur:	reg:
451177 ZOCH LOOP 6"				I	N
412501		The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.	Entire pipeline		
		Requirement: 49 CFR 195.412(a)			

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RRCII 02392

442503 The written damage prevention program was insufficient in the following areas:

Location: Pinoak Creek

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

KOCH PL / LONGVIEW

ID and Name: 351750 ADD'L LATERALS OFF MAINLINE

jur: I req: N

code	text	notes
404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection. Requirement: 49 CFR 195.404(c)(3)	
410503	The aboveground pipeline(s) listed below did not have line markers. Requirement: 49 CFR 195.410(c)	Location: McBee Fisher pump discharge Doby B
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year. Requirement: 49 CFR 195.412(a)	Location: Doby Orms person Mainline S G Smith pig rcvr Adrian McCrary pig rcvr

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RRCII 02393

- 440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

- 442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

- 786501 The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating.

Location: E.M. Whatley Person mainline

Requirement: 16 TAC 7.86(1)

- 786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: McBee Fisher pump discharge
S. G. Smith Pig Launcher
C. L. Pig Launch
Doby Pig Launch

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 351756 ANDERSON GATHERING

jur: I req: N

code	text	notes
404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection. Requirement: 49 CFR 195.404(c)(3)	Location: Ingram Station pump
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Being corrected
440501	A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency. Requirement: 49 CFR 195.440	
442503	The written damage prevention program was insufficient in the following areas: a. Records of excavation - related persons were not maintained or were not current. b. Procedures for notification to the public of the program and its purpose were not available or were not followed. c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed. d. Procedures for documentation of planned excavation activities were not available or were not followed. e. Procedures for marking pipelines prior to excavation activity were not available or were not followed. f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed. Requirement: 49 CFR 195.442(b)	

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RRCII 02395

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: R B White LACT
R B White rcvr

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 351759 FISHER GATHERING

Jur: I req: N

code text

notes

404510 Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.

Location: Fisher Pump
White Station pump

Requirement: 49 CFR 195.404(c)(3)

410503 The aboveground pipeline(s) listed below did not have line markers.

Location: Amoco T B harris pump disch

Requirement: 49 CFR 195.410(c)

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Being corrected

Requirement: 49 CFR 195.416(a)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: T B Harris Stock Tank disch
Harris B pig rcvr
Amoco T B Harris pump disch
Amoco T B Harris tie Harris C

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851361 GLADEWATER GATHERING

Jur: I req: N

code text

notes

242501 Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.

Location: Boucknight pump 614 mv
Beginning Gladewater 6" traps 547 mv

Requirement: 49 CFR 195.242(a)

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RRCII 02396

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Entire system

Requirement: 49 CFR 195.412(a)

ID and Name: 351762 HARRIS-NORTON MAINLINE

Jur: I reg: N

code text

notes

404510 Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.

Location: Horton Sta. pumps

Requirement: 49 CFR 195.404(c)(3)

440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

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RRCII 02397

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

ID and Name: 351755 INGRAM GATHERING		jur: I	req: N
code	text	notes	
404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.		
	Requirement: 49 CFR 195.404(c)(3)		
410503	The aboveground pipeline(s) listed below did not have line markers.	Location: Helen Pritchard B LACT Jelen Pritchard A pig launch	
	Requirement: 49 CFR 195.410(c)		
440501	A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.		
	Requirement: 49 CFR 195.440		

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RRCII 02398

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Todd Stinchomb LACT
Powell T & PRY K Stock Tank

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 351754 KEY CORNER GATHERING

Jur: I reg: N

code	text	notes
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404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.	
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Requirement: 49 CFR 195.404(c)(3)

410503 The aboveground pipeline(s) listed below did not have line markers.

Location: O J Albright pump disch.

Requirement: 49 CFR 195.410(c)

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Location: Akin rcvr and tie in

Requirement: 49 CFR 195.412(a)

440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: O J Albright pump disch.

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 351752 LACY-SNYDER GATHERING

jur: I reg: N

code	text	notes
404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection. Requirement: 49 CFR 195.404(c)(3)	
410503	The aboveground pipeline(s) listed below did not have line markers. Requirement: 49 CFR 195.410(c)	Location: Bun Rodden lease
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year. Requirement: 49 CFR 195.412(a)	Location: Amoco Skipper Gardner line
440501	A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency. Requirement: 49 CFR 195.440	

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RRCII 02401

- 442503 The written damage prevention program was insufficient in the following areas:
- a. Records of excavation - related persons were not maintained or were not current.
 - b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
 - c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
 - d. Procedures for documentation of planned excavation activities were not available or were not followed.
 - e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
 - f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: S G Smith A pig launch
S G Smith A pig rcvr
S G Smith B pig launch
Key Skipper Gardner pump disch
Bob Eood pump dish

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851367 LAKE DIVERNIA LEG

Jur: I reg: N

code	text	notes
242501	Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.	Locations: All inactive system
	Requirement: 49 CFR 195.242(a)	
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.	Entire system
	Requirement: 49 CFR 195.412(a)	

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RRCH 02402

ID and Name: 351749 MAINLINE

jur: I reg: N

code	text	notes
404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection. Requirement: 49 CFR 195.404(c)(3)	Location: Monday Station pump
440501	A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency. Requirement: 49 CFR 195.440	
442503	The written damage prevention program was insufficient in the following areas: a. Records of excavation - related persons were not maintained or were not current. b. Procedures for notification to the public of the program and its purpose were not available or were not followed. c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed. d. Procedures for documentation of planned excavation activities were not available or were not followed. e. Procedures for marking pipelines prior to excavation activity were not available or were not followed. f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed. Requirement: 49 CFR 195.442(b)	

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RRCII 02403

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Crossover 10" to 8"

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851363 MIDDLE 1/3

jur: I reg: N

code	text	notes
242501	Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.	Location: Start of 6" at Smith 645mv Ben Laird Lease 202 mv Russell B Tie in 235 mv
Requirement: 49 CFR 195.242(a)		

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Requirement: 49 CFR 195.412(a)

ID and Name: 851364 MIDDLE 1/3 BP, KOCH

jur: I reg: N

code	text	notes
242501	Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.	Locations: Smith-Horton 4" 603mv Mary King Lease 268mv Mary King EOL 434mv
Requirement: 49 CFR 195.242(a)		

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Requirement: 49 CFR 195.412(a)

ID and Name: 851362 MOBIL GATHERING

jur: I reg: N

code	text	notes
242501	Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.	Location: All inactive system
Requirement: 49 CFR 195.242(a)		

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RRCH 02404

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Requirement: 49 CFR 195.412(a)

ID and Name: 851348 MOBIL-SNODDY GATHERING

jur: I reg: N

code	text	notes
404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.	
	Requirement: 49 CFR 195.404(c)(3)	
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.	Being corrected
	Requirement: 49 CFR 195.416(a)	
440501	A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.	
	Requirement: 49 CFR 195.440	

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Texaco Taylor Stck Tank Disch.

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851365 MONDAY LEG

Jur: I reg: N

code	text	notes
242501	Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.	Locations: Dollahite Block Valve 384mv Beulah Jones A 503mv Finley Thomas A&B 571mv
Requirement: 49 CFR 195.242(a)		

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Entire system

Requirement: 49 CFR 195.412(a)

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RRCII 02406

ID and Name: 851366 NORTH 1/3 GATHERING

Jur: I reg: N

code	text	notes
242501	Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected. Requirement: 49 CFR 195.242(a)	Locations: Boston Moore 688mv Castleberry Jones 376mv JC McKinley A 433mv Duncan Lease 21mv Hays A&B 499mv
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year. Requirement: 49 CFR 195.412(a)	Entire system

ID and Name: 851347 POWELL GATHERING

Jur: I reg: N

code	text	notes
404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection. Requirement: 49 CFR 195.404(c)(3)	
410503	The aboveground pipeline(s) listed below did not have line markers. Requirement: 49 CFR 195.410(c)	Location: Caddie Fisher pig rcvr
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year. Requirement: 49 CFR 195.412(a)	Location: G W Tate LACT Powell Coldwell Tie Irene Ziegler
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Being corrected

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RRCII 02407

440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786501 The exposed aboveground pipeline(s) at the following site(s) was not protected from atmospheric corrosion with coating, jacketing, or other surface treating.

Location: Powell Coldwell Common Pt
TPR & Y Fee Stock Tank dish

Requirement: 16 TAC 7.86(1)

ID and Name: 351758 RODDEN GATHERING

Jur: I reg: N

code text

notes

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RRCII 02408

- 404510 Records were ~~not~~ maintained on each required inspection and test for at least two years or until the next test or inspection.

Requirement: 49 CFR 195.404(c)(3)

- 412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Location: Arco R A Penn
Arco Smith pig rcvr

Requirement: 49 CFR 195.412(a)

- 416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Being corrected

Requirement: 49 CFR 195.416(a)

- 440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Requirement: 16 TAC 7.86(4)(B)

Location: Arco R A Penn Stock Tank disch
Arco R A Penn tie in
B. Rodden Stock Tank disch
Bun Rodden Stock Tank disch
Arco Rodden pig rcvr
Bun Rodden pig rcvr

ID and Name: 351767 SMITH-EXXON 3"

jur: I req: N

code	text	notes
410503	The aboveground pipeline(s) listed below did not have line markers.	Location: Smith LACT discharge This alleged violation was corrected during the evaluation.
Requirement: 49 CFR 195.410(c)		

785501 The pipeline listed below was not constructed of steel and had not been granted a special exception by the Railroad Commission.

Requirement: 16 TAC 7.85

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RRCII 02410

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Smith LACT discharge riser -620
MV

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 351753 SNODDY GATHERING

Jur: I reg: N

code text

notes

404510 Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.

Requirement: 49 CFR 195.404(c)(3)

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Location: McKinley A

Requirement: 49 CFR 195.412(a)

440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

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RRCH 02411

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Requirement: 16 TAC 7.86(4)(B)

Location: G B Tannery Arco
Moss Tannery
McKinley B.E. pig launch
McKinley A riser
J G McGrede pig rcvr
Lathrop BB pig rcvr
J Snoddy pig launch
Herman Snoddy riser
Thad Snoddy pig launch
Snoddy E pump disch
Davis B pig launch
S G & maude Smith 'C' pig launch

ID and Name: 851369 SOUTH 1/3

jur: I req: N

code text

notes

242501 Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.

Locations: All inactive system

Requirement: 49 CFR 195.242(a)

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RRCH 02412

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Entire system

Requirement: 49 CFR 195.412(a)

ID and Name: 851368 SOUTH 1/3 BP, KOCH

Jur: I req: N

code text

notes

242501 Buried or submerged pipeline(s) at the listed location(s) was not cathodically protected.

Locations: All inactive system

Requirement: 49 CFR 195.242(a)

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Entire system

Requirement: 49 CFR 195.412(a)

ID and Name: 351763 STINCHCOMB TRUNKLINE

Jur: I req: N

code text

notes

404510 Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.

Requirement: 49 CFR 195.404(c)(3)

410503 The aboveground pipeline(s) listed below did not have line markers.

Location: Martin Hays lease

Requirement: 49 CFR 195.410(c)

440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

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RRCII 02413

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Percy McGeorge lease
Percy McGeorge tie in
Martin Hays Stock tank disch.
Mainline block valve Martin Hays tie in

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 351751 THRASHER GATHERING

jur: I reg: N

code	text	notes
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404510	Records were not maintained on each required inspection and test for at least two years or until the next test or inspection.	
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Requirement: 49 CFR 195.404(c)(3)

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RRCII 02414

440501 A continuing educational program was not established to teach the public, government organizations, or persons engaged in excavation-related activities how to recognize and report a hazardous liquid or carbon dioxide pipeline emergency.

Requirement: 49 CFR 195.440

442503 The written damage prevention program was insufficient in the following areas:

- a. Records of excavation - related persons were not maintained or were not current.
- b. Procedures for notification to the public of the program and its purpose were not available or were not followed.
- c. Procedures for notifying excavation-related persons of the program and its purpose were not available or were not followed.
- d. Procedures for documentation of planned excavation activities were not available or were not followed.
- e. Procedures for marking pipelines prior to excavation activity were not available or were not followed.
- f. Procedures to determine the necessity of inspecting pipelines during and after excavation activity were not available or were not followed.

Requirement: 49 CFR 195.442(b)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Location: Pet Hopkins pig launch
Pet Hopkins pig rcvr
J T Hopkins pump discharge
Minnie Jones lease

Requirement: 16 TAC 7.86(4)(B)

KOCH PL / MEDFORD

ID and Name: 851229 CRUDE/MUENSTER

jur: I req: N

code text notes

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RRCII 02415

005504	The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E.	All systems
	Requirement: 49 CFR 195.5(a)(4)	
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.	Entire system
	Requirement: 49 CFR 195.416(a)	
416503	The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.	All rectifiers
	Requirement: 49 CFR 195.416(c)	
420502	The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly.	All block valves
	Requirement: 49 CFR 195.420(b)	
420503	The listed valve(s) was not protected from unauthorized operation and/or vandalism.	All block valves
	Requirement: 49 CFR 195.420(c)	
428501	The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months.	All pressure control equipment
	Requirement: 49 CFR 195.428(a)	
432501	The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months.	Breakout/storage tanks were not inspected.
	Requirement: 49 CFR 195.432	
784514	Records of hydrostatic testing of the pipeline and/or components were not maintained.	
	Requirement: 16 TAC 7.84(e)(3)	

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RRCII 02416

786502 The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. the entire system

Requirement: 16 TAC 7.86(1)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Black Top Rd. -.780v County RD 415 -.762v
I-35 -.678v Storage Tank -.621v

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851227 GAINESVILLE, BEST DISCH.

jur: O reg: N

code	text	notes
005504	The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E.	All systems
	Requirement: 49 CFR 195.5(a)(4)	
412501	The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.	A. Rectifier 688 B. Best station
	Requirement: 49 CFR 195.412(a)	
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.	Entire system
	Requirement: 49 CFR 195.416(a)	
416503	The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.	All rectifiers
	Requirement: 49 CFR 195.416(c)	

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RRCH 02417

- | | | |
|--------|---|--|
| 418504 | The pipeline(s) at the listed location(s) was not monitored twice each calendar year, with intervals not exceeding seven and one-half months, to determine the effectiveness of the inhibitors or the degree of internal corrosion. | Entire system |
| | Requirement: 49 CFR 195.418(c) | |
| 420502 | The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. | All block valves |
| | Requirement: 49 CFR 195.420(b) | |
| 428501 | The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. | All pressure control equipment |
| | Requirement: 49 CFR 195.428(a) | |
| 432501 | The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. | Breakout/storage tanks were not inspected. |
| | Requirement: 49 CFR 195.432 | |
| 784514 | Records of hydrostatic testing of the pipeline and/or components were not maintained. | |
| | Requirement: 16 TAC 7.84(e)(3) | |
| 786502 | The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. | The entire system |
| | Requirement: 16 TAC 7.86(1) | |
| 786508 | The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: | Red River Valve -.660v Tank -.710v |
| | Requirement: 16 TAC 7.86(4)(B) | |

ID and Name: 851228 GAINESVILLE, NOCONA LEG

jur: O req: N

code text

notes

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RRCII 02418

- | | | |
|--------|---|--------------------------------|
| 005504 | The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E. | All systems |
| | Requirement: 49 CFR 195.5(a)(4) | |
| 416501 | Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. | Entire system |
| | Requirement: 49 CFR 195.416(a) | |
| 416503 | The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months. | All rectifiers |
| | Requirement: 49 CFR 195.416(c) | |
| 416507 | The line segment(s) was not repaired or replaced at the listed location(s) where localized corrosion pitting existed to a degree that leakage could occur. | Highway 2953 |
| | Requirement: 49 CFR 195.416(g) | |
| 418504 | The pipeline(s) at the listed location(s) was not monitored twice each calendar year, with intervals not exceeding seven and one-half months, to determine the effectiveness of the inhibitors or the degree of internal corrosion. | Entire system |
| | Requirement: 49 CFR 195.418(c) | |
| 420502 | The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. | All block valves |
| | Requirement: 49 CFR 195.420(b) | |
| 428501 | The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. | All pressure control equipment |
| | Requirement: 49 CFR 195.428(a) | |

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RRCU 02419

432501 The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Breakout/storage tanks were not inspected.

Requirement: 49 CFR 195.432

784514 Records of hydrostatic testing of the pipeline and/or components were not maintained.

Requirement: 16 TAC 7.84(e)(3)

786502 The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period.

The entire system

Requirement: 16 TAC 7.86(1)

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

M.P. 2953 -.828v

Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851226 GAINESVILLE, SHERMAN LEG

jur: I reg: N

code	text	notes
005504	The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E.	All systems
	Requirement: 49 CFR 195.5(a)(4)	

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RRCH 02420

410502 Line markers were inadequate because of the following reason(s): Sherman Station

a. They did not have the words "Warning" followed by "Petroleum (or name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline."

b. The letters were not at least one-inch high with one-quarter inch stroke.

c. The background color did not contrast sharply with the lettering.

d. They did not have the operator's name.

e. They did not have the operator's 24-hour telephone number.

f. They did not have the operator's 24-hour telephone area code.

Requirement: 49 CFR 195.410(a)(2)

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Requirement: 49 CFR 195.412(a)

A. Highway 82
B. Sherman Plant Road
C. Highway 901

Records indicated inspections are being performed at scheduled intervals by air patrol. It appears that effective patrolling along some sections of this pipeline cannot be accomplished because of heavy growth of underbrush and trees.

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Requirement: 49 CFR 195.416(a)

Entire system

416503 The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.

Requirement: 49 CFR 195.416(c)

All rectifiers

- 418504 The pipeline(s) at the listed location(s) was not monitored twice each calendar year, with intervals not exceeding seven and one-half months, to determine the effectiveness of the inhibitors or the degree of internal corrosion. Entire system
Requirement: 49 CFR 195.418(c)
- 420502 The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. All block valves
Requirement: 49 CFR 195.420(b)
- 428501 The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. All pressure control equipment
Requirement: 49 CFR 195.428(a)
- 432501 The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Breakout/storage tanks were not inspected.
Requirement: 49 CFR 195.432
- 784514 Records of hydrostatic testing of the pipeline and/or components were not maintained.
Requirement: 16 TAC 7.84(e)(3)
- 786502 The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. The entire system
Requirement: 16 TAC 7.86(1)
- 786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: Valve at Hwy 901 -.611v Trap -.750v
Requirement: 16 TAC 7.86(4)(B)

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RRCII 02422

786511 The listed interference bond was not electrically checked for performance once each calendar year with intervals not exceeding 15 months

All bonds were not inspected

Requirement: 16 TAC 7.86(5)(B)

ID and Name: 551956 NEEDERLAND 8"

jur: I req: N

code text

notes

000000 No violations

KOCH PL / MIDLAND

ID and Name: 851220 ACKERLEY

jur: I req: N

code text

notes

005504 The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E.

Ackerly Systems

Requirement: 49 CFR 195.5(a)(4)

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Entire system

Requirement: 49 CFR 195.416(a)

416503 The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.

All rectifiers

Requirement: 49 CFR 195.416(c)

418504 The pipeline(s) at the listed location(s) was not monitored twice each calendar year, with intervals not exceeding seven and one-half months, to determine the effectiveness of the inhibitors or the degree of internal corrosion.

The entire system

Requirement: 49 CFR 195.418(c)

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RRCII 02423

420502	The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly.	All block valves
	Requirement: 49 CFR 195.420(b)	
428501	The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months.	Records were inadequate to demonstrate that any pressure control equipment was inspected.
	Requirement: 49 CFR 195.428(a)	
432501	The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months.	Records were inadequate to demonstrate that any tank was inspected each calendar year.
	Requirement: 49 CFR 195.432	
784514	Records of hydrostatic testing of the pipeline and/or components were not maintained.	
	Requirement: 16 TAC 7.84(e)(3)	
786502	The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period.	The entire system
	Requirement: 16 TAC 7.86(1)	

ID and Name: 851232 DRIVER GATHERING

jur: I reg: N

code	text	notes
410501	Line markers were not placed or maintained over the following buried pipeline(s).	Along the pipeline right of way.
	Requirement: 49 CFR 195.410(a)(1)	Line markers were not placed in sufficient numbers along the R-O-W to reflect the pipeline route

410502 Line markers were inadequate because of the following reason(s):

The markers were not changed out from the previous operator (Still reflected Shell)

a. They did not have the words "Warning" followed by "Petroleum (or name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline."

b. The letters were not at least one-inch high with one- quarter inch stroke.

c. The background color did not contrast sharply with the lettering.

d. They did not have the operator's name.

e. They did not have the operator's 24-hour telephone number.

f. They did not have the operator's 24-hour telephone area code.

Requirement: 49 CFR 195.410(a)(2)

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Selected areas along the right of way.

Vegetation growth was to the extent that adequate aerial patrols could not have been performed.

Requirement: 49 CFR 195.412(a)

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Entire Driver Gathering System

Requirement: 49 CFR 195.416(a)

420502 The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly.

Each valve that would be necessary to ensure the safe operation of the pipeline system.

Requirement: 49 CFR 195.420(b)

420503 The listed valve(s) was not protected from unauthorized operation and/or vandalism.

Main Line Valve sites

Requirement: 49 CFR 195.420(c)

428501	The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.428(a)	Pump shut downs.
432501	The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.432	Each break-out tank within the system.
786502	The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. Requirement: 16 TAC 7.86(1)	Above ground valves sites and station piping.
786508	The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: Requirement: 16 TAC 7.86(4)(B)	Exxon Sherrod Lateral -676mv

ID and Name: 851221 GARZA SYS.

jur: I req: N

code	text	notes
005504	The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E. Requirement: 49 CFR 195.5(a)(4)	
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Entire system
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Entire system

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RRCH 02426

- 416502 Test leads at the following location(s) were not maintained so that the cathodic protection's adequacy could be determined. County Road 424
Requirement: 49 CFR 195.416(b)
- 416503 The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months. All rectifiers
Requirement: 49 CFR 195.416(c)
- 420502 The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. All block valves
Requirement: 49 CFR 195.420(b)
- 428501 The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. All pressure control equipment
Requirement: 49 CFR 195.428(a)
- 432501 The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Garza Tank
Requirement: 49 CFR 195.432
- 784514 Records of hydrostatic testing of the pipeline and/or components were not maintained.
Requirement: 16 TAC 7.84(e)(3)
- 786502 The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. The entire system
Requirement: 16 TAC 7.86(1)

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RRCII 02427

786509 The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.

Garza
1. Discharge at Station -.768v
2. FM 612 -.789v
3. Enserch -.793v

Requirement: 16 TAC 7.86(5)(A)

ID and Name: 851222 HASKELL (WEST LEG)

jur: I reg: N

code text

notes

005504 The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E.

Requirement: 49 CFR 195.5(a)(4)

266506 A complete record was not maintained on the location of:

A. each valve B. each corrosion test station

a. each valve

b. each corrosion test station

Requirement: 49 CFR 195.266(f)

410502 Line markers were inadequate because of the following reason(s):

A. Haskell station B. Peak Booster

a. They did not have the words "Warning" followed by "Petroleum (or name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline."

b. The letters were not at least one-inch high with one-quarter inch stroke.

c. The background color did not contrast sharply with the lettering.

d. They did not have the operator's name.

e. They did not have the operator's 24-hour telephone number.

f. They did not have the operator's 24-hour telephone area code.

Requirement: 49 CFR 195.410(a)(2)

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RRCII 02428

- | | | |
|--------|--|---|
| 412501 | The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year. | A. Brown C
B. Rectifier 219
C. Peak Booster
D. QQQ 9 |
| | Requirement: 49 CFR 195.412(a) | |
| <hr/> | | |
| 416501 | Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. | Entire system |
| | Requirement: 49 CFR 195.416(a) | |
| <hr/> | | |
| 416501 | Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. | Entire system |
| | Requirement: 49 CFR 195.416(a) | |
| <hr/> | | |
| 416503 | The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months. | All rectifiers |
| | Requirement: 49 CFR 195.416(c) | |
| <hr/> | | |
| 420502 | The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. | Katz Station |
| | Requirement: 49 CFR 195.420(b) | |
| <hr/> | | |
| 428501 | The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. | All pressure control equipment |
| | Requirement: 49 CFR 195.428(a) | |
| <hr/> | | |
| 784514 | Records of hydrostatic testing of the pipeline and/or components were not maintained. | |
| | Requirement: 16 TAC 7.84(e)(3) | |
| <hr/> | | |

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RRCII 02429

786502	The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. Requirement: 16 TAC 7.86(1)	The entire system
786508	The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: Requirement: 16 TAC 7.86(4)(B)	Brown C
786514	Prompt remedial action was not taken to correct cathodic protection deficiencies found at the listed location(s): Requirement: 16 TAC 7.86(6)	Haskell 1. Brown C -.675 v (west) 2. N -.641 v (east) 3. FM 617 -.719 (Katz to Haskell)

ID and Name: 851230 MCELROY GATHERING

jur: I reg: N

code	text	notes
410501	Line markers were not placed or maintained over the following buried pipeline(s). Requirement: 49 CFR 195.410(a)(1)	Along the pipeline R-O-W. Line markers were not placed in sufficient numbers along the R-O-W to reflect the pipeline route.
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Along the pipeline R-O-W.
420502	The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. Requirement: 49 CFR 195.420(b)	Each valve that would be necessary to ensure the safe operation of the pipeline system.
420503	The listed valve(s) was not protected from unauthorized operation and/or vandalism. Requirement: 49 CFR 195.420(c)	Main line valve sites

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RRCII 02430

428501	The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.428(a)	Pump shut downs
432501	The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.432	Each break-out tank within the system
786502	The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. Requirement: 16 TAC 7.86(1)	Above ground valve sites and station piping.
786508	The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: Requirement: 16 TAC 7.86(4)(B)	Amacker Sation #131 -798 mv

ID and Name: 851223 PARDUE

jur: I reg: N

code	text	notes
005504	The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E. Requirement: 49 CFR 195.5(a)(4)	All systems
266506	A complete record was not maintained on the location of: a. each valve b. each corrosion test station Requirement: 49 CFR 195.266(f)	a. each valve b. each corrosion test station

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RRCII 02431

- | | | |
|--------|---|--------------------------------|
| 416501 | Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Requirement: 49 CFR 195.416(a) | Entire system |
| <hr/> | | |
| 416501 | Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Requirement: 49 CFR 195.416(a) | Entire system |
| <hr/> | | |
| 416503 | The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.

Requirement: 49 CFR 195.416(c) | All rectifiers |
| <hr/> | | |
| 420502 | The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly.

Requirement: 49 CFR 195.420(b) | Valve at tank |
| <hr/> | | |
| 428501 | The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months.

Requirement: 49 CFR 195.428(a) | All pressure control equipment |
| <hr/> | | |
| 784514 | Records of hydrostatic testing of the pipeline and/or components were not maintained.

Requirement: 16 TAC 7.84(e)(3) | |
| <hr/> | | |
| 786502 | The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period.

Requirement: 16 TAC 7.86(1) | The entire system |

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RRCII 02432

786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:

Pardue
1. Young Rectifier -.215v
2. Highway 540 -.315v

Requirement: 16 TAC 7.86(4)(B)

786509 The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.

On highway

Requirement: 16 TAC 7.86(5)(A)

ID and Name: 851231 QUITO CRUDE GATHERING

jur: I req: N

code	text	notes
404504	The maps and records of the pipeline system did not include the maximum operating pressure of each pipeline. Requirement: 49 CFR 195.404(a)(3)	
410501	Line markers were not placed or maintained over the following buried pipeline(s). Requirement: 49 CFR 195.410(a)(1)	Along the Piping R-O-W Line markers were not placed in sufficient numbers along the R-O-W to reflect the piping route.
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Entire Quito Gathering System
420502	The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. Requirement: 49 CFR 195.420(b)	Each valve that would be necessary to ensure the safe operation of the pipeline system
420503	The listed valve(s) was not protected from unauthorized operation and/or vandalism. Requirement: 49 CFR 195.420(c)	Oxy-Texaco tie-in T/S no. 51

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RRCII 02433

- 428501 The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months.
Pump shut downs
Requirement: 49 CFR 195.428(a)
- 786502 The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period.
Above ground valve sites and station piping
Requirement: 16 TAC 7.86(1)
- 786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:
T/S no. 151 Oxy-tie in -603mv
Requirement: 16 TAC 7.86(4)(B)

ID and Name: 851224 STONEWALL GATH. SYSTEM

jur: I req: N

code	text	notes
005504	The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E. Requirement: 49 CFR 195.5(a)(4)	All systems
266506	A complete record was not maintained on the location of: a. each valve b. each corrosion test station Requirement: 49 CFR 195.266(f)	a. each valve b. each corrosion test station

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RRCII 02434

410502 Line markers were inadequate because of the following reason(s):

- a. They did not have the words "Warning" followed by "Petroleum (or name of the hazardous liquid transported) Pipeline" or "Carbon Dioxide Pipeline."
- b. The letters were not at least one-inch high with one- quarter inch stroke.
- c. The background color did not contrast sharply with the lettering.
- d. They did not have the operator's name.
- e. They did not have the operator's 24-hour telephone number.
- f. They did not have the operator's 24-hour telephone area code.

Requirement: 49 CFR 195.410(a)(2)

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Requirement: 49 CFR 195.412(a)

A. River valve
B. Mal. Junction
C. Flower riser
D. Frankink pump
Records indicate inspections are being performed at scheduled intervals by air patrol. It appears that effective patrolling along some sections of this pipeline cannot be accomplished because of heavy growth of underbrush and trees.

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Requirement: 49 CFR 195.416(a)

Entire system

416503 The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.

Requirement: 49 CFR 195.416(c)

All rectifiers

- 420502 The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. All block valves
Requirement: 49 CFR 195.420(b)
- 420503 The listed valve(s) was not protected from unauthorized operation and/or vandalism. North side of river
Requirement: 49 CFR 195.420(c)
- 428501 The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. All pressure control equipment
Requirement: 49 CFR 195.428(a)
- 784514 Records of hydrostatic testing of the pipeline and/or components were not maintained.
Requirement: 16 TAC 7.84(e)(3)
- 786502 The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. The entire system
Requirement: 16 TAC 7.86(1)
- 786508 The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69:
Requirement: 16 TAC 7.86(4)(B)

Stonewall
1. Flowers -.801v
2. EOL -.588v
3. Rutherford -.494v
4. Frankin .472v

ID and Name: 851225 TRENT

jur: I reg: N

- | code | text | notes |
|--------|---|-------------|
| 005504 | The pipeline was not tested to substantiate the maximum allowable operating pressure as required by Subpart E.
Requirement: 49 CFR 195.5(a)(4) | All systems |

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RRCH 02436

266506 A complete record was not maintained on the location of:

a. each valve

b. each corrosion test station

Requirement: 49 CFR 195.266(f)

A. each valve b. each corrosion test station

412501 The surface conditions on or adjacent to the pipeline right(s)-of-way at the location(s) below were not inspected at intervals not exceeding three weeks, and at least 26 times per calendar year.

Requirement: 49 CFR 195.412(a)

Railroad crossing

Records indicate inspections are being performed at scheduled intervals by air patrol. It appears that effective patrolling along some sections of this pipeline cannot be accomplished because of heavy growth of underbrush and trees.

Records indicate inspections are being performed at scheduled intervals by air patrol. It appears that effective patrolling along some sections of this pipeline cannot be accomplished because of heavy growth of underbrush and trees.

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Requirement: 49 CFR 195.416(a)

Entire system

416501 Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals.

Requirement: 49 CFR 195.416(a)

Entire system

416503 The cathodic protection rectifier(s) at the site(s) below was not inspected six times each calendar year, with intervals not exceeding two and one-half months.

Requirement: 49 CFR 195.416(c)

All rectifiers

420502 The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly.

Requirement: 49 CFR 195.420(b)

All block valves

Thursday, April 02, 1998

Page 66 of 68

RRCH 02437

- | | | |
|--------|--|--------------------------------|
| 420502 | The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. | All valves |
| | Requirement: 49 CFR 195.420(b) | |
| <hr/> | | |
| 420502 | The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. | Trent tank |
| | Requirement: 49 CFR 195.420(b) | |
| <hr/> | | |
| 428501 | The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. | All pressure control equipment |
| | Requirement: 49 CFR 195.428(a) | |
| <hr/> | | |
| 432501 | The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. | Trent tank |
| | Requirement: 49 CFR 195.432 | |
| <hr/> | | |
| 784514 | Records of hydrostatic testing of the pipeline and/or components were not maintained. | |
| | Requirement: 16 TAC 7.84(e)(3) | |
| <hr/> | | |
| 786502 | The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. | The entire system |
| | Requirement: 16 TAC 7.86(1) | |
| <hr/> | | |
| 786508 | The level of cathodic protection for the pipe system(s) listed below did not meet the criteria set forth in "Criteria For Cathodic Protection," of the most current edition of NACE Standard RP-01-69: | Trent
1. Trent Tank -.781v |
| | Requirement: 16 TAC 7.86(4)(B) | |

ID and Name: 851233 UPTON CRUDE GATHERING

jur: 1 reg: N

code text

notes

Thursday, April 02, 1998

Page 67 of 68

RRCII 02438

410501	Line markers were not placed or maintained over the following buried pipeline(s). Requirement: 49 CFR 195.410(a)(1)	Along the Pipeline R-O-W Line markers were not placed in sufficient numbers along the R-O-W to reflect the pipeline route.
416501	Tests for adequate cathodic protection were not performed on the listed underground facility(ies) once each year within 15 month intervals. Requirement: 49 CFR 195.416(a)	Entire Upton Gathering System
420502	The listed line valve(s) was not inspected twice each calendar year, with intervals not exceeding seven and one-half months, to determine if it was functioning properly. Requirement: 49 CFR 195.420(b)	Each valve that would benecessary to ensure the safe operation of the pipeline system
420503	The listed valve(s) was not protected from unauthorized operation and/or vandalism. Requirement: 49 CFR 195.420(c)	Main Line valve sites
428501	The pressure control equipment specified below was not inspected and/or tested once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.428(a)	Pump shut downs
432501	The following breakout tank(s) was not inspected at least once each calendar year, with intervals not exceeding 15 months. Requirement: 49 CFR 195.432	Each break-out tank within the system
786502	The onshore pipeline(s) exposed to the atmosphere at the listed location(s) was not reevaluated for atmospheric corrosion within a five year period. Requirement: 16 TAC 7.86(1)	Above ground valve sites and station piping

Thursday, April 02, 1998

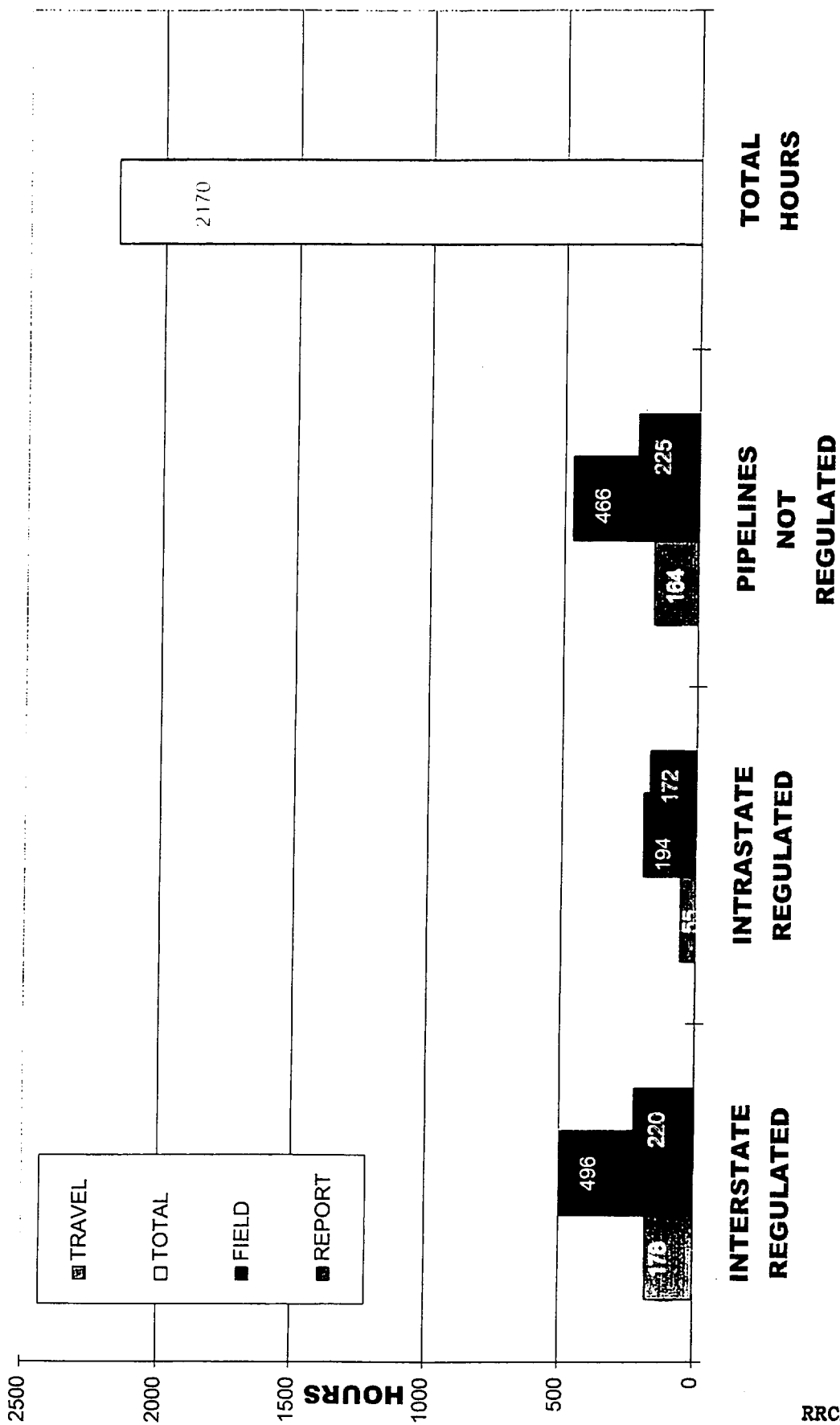
Page 68 of 68

RRCII 02439

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RRCII 02440

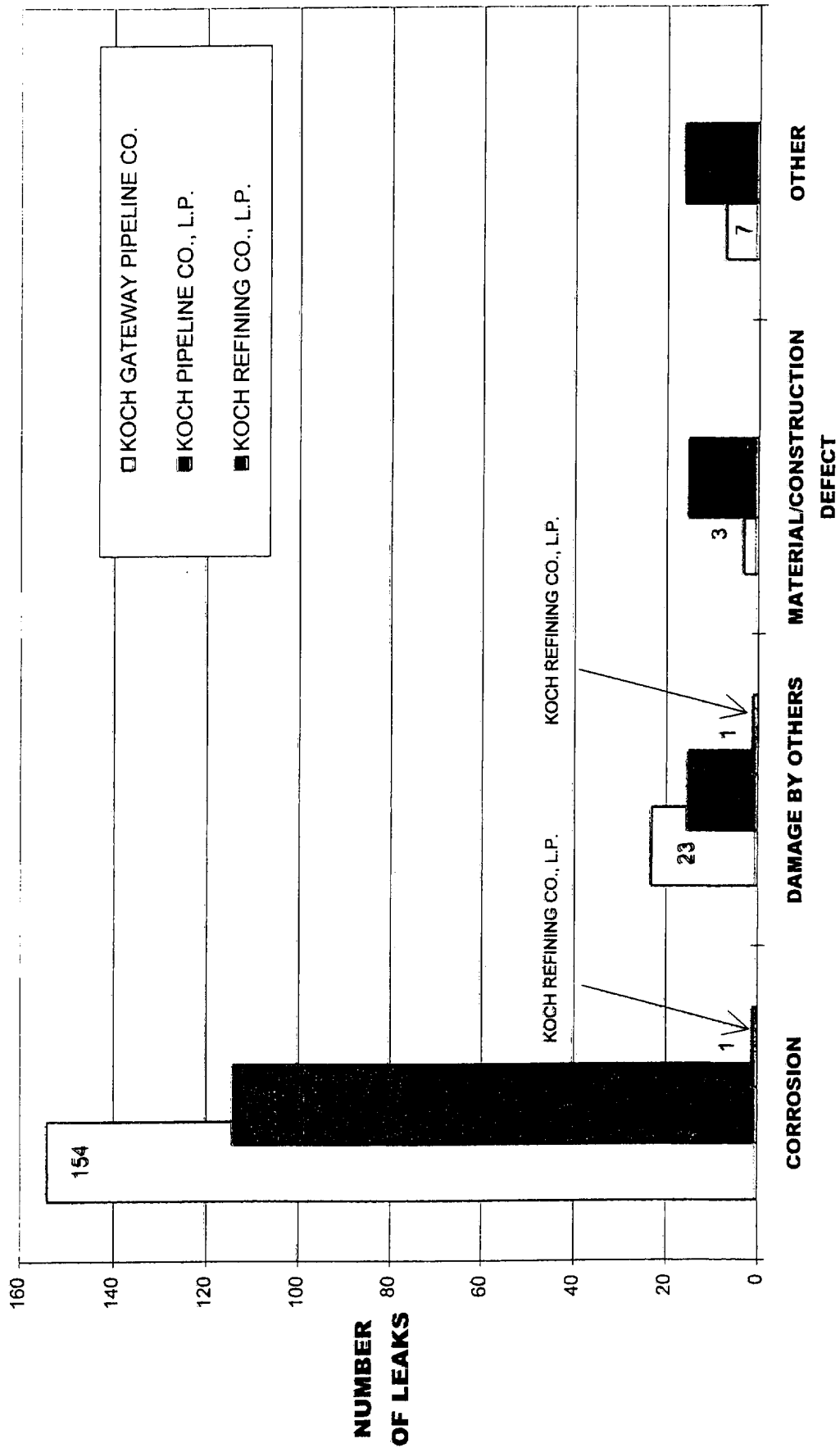
TIME EXPENDED



RRCII 02441

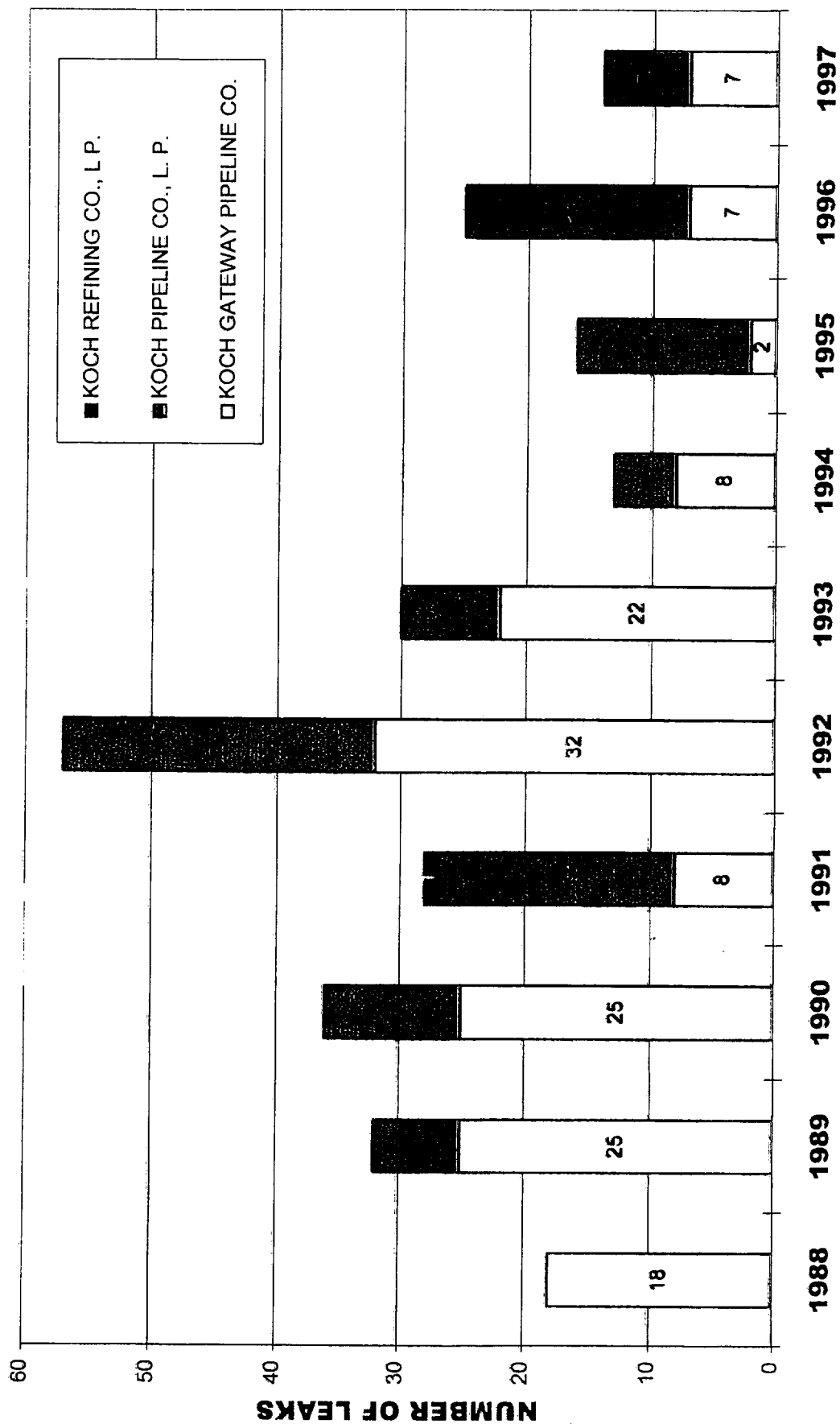
74

EXHIBIT NO. 3
LEAK SUMMARY LAST 10 YEARS



RRCII 00886

**EXHIBIT NO. 4
CORROSION**



RRCH 00898

75



U.S. Department
of Transportation

**Research and
Special Programs
Administration**

Southwest Region,
Pipeline Safety

2320 La Branch
Houston, TX 77004

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 30, 1998

Mr. Dan Stecklein
Vice President of Operation
Koch Gateway Pipeline Company
P.O. Box 1478
Houston, Texas 77251-1478

Dear Mr. Stecklein:

CPF No. 48111W

Between May 4 to 28, 1998, a representative of the Southwest Region, Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of the facilities, operating and maintenance (O&M) procedures manuals and pipeline records of Koch Gateway Pipeline Company, in the Goodrich Area Office (Former Spring Division II, including the Goodrich Area Office and Magasco Area Office).

As a result of the inspection, it appears that you have committed probable violations of the pipeline safety regulations, Title 49, Code of Federal Regulations, Part 192. The probable violations are:

1. **§192.465 (a) External corrosion control: Monitoring:** Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463.

Records were reviewed in your Goodrich Area Office and in some locations of your Index-70 from Boggy Creek - Huntsville; Index-59 from Woskom - Goodrich, and Trinity City Gate. The review showed that Koch Gateway's cathodic protection was inadequate at some locations in 1995 and 1996. Additionally, you have not taken prompt remedial action to correct any deficiency indicated by these monitorings:

Location Line 070	Milepost	Struc P/S 1995 (mv)	Struc P/S 1996 (mv)
Farm Tap (Brynts)	49.250	-0.734	-0.702
Test Lead (dirt road)	51.000	-0.752	-0.725
Test Lead (dirt road)	51.500	no reading	-0.658
Test Lead at Marker	52.000	-0.705	-0.662
Test Lead Creek Bed	57.000	-0.782	-0.668
Well Tie-in TF	62.950	-0.830	-0.763
Blow-ff Tanabo Creek	63.250	-0.823	-0.767
TPL 70-7: Trinity City Gate Tap-TU	68.000	-0.785	-0.733
TPL 70-7: Trinity CG: MP .01	68.000A	-0.785	no reading
Farm Tap-FM #356	68.250	-0.730	-0.734
Index 070-07-00-00 Trinity City Gate			
Entex-End of Line	0.000	-0.794	-0.750
Location Line 059			
Test Lead	94.770	no reading	-0.578
Old Neg. TL only	95.071	-0.470	-0.540
Test Lead	95.170	no reading	-0.471
Old Neg.LD./TL Only	95.331	-0.313	-0.462
Old Neg. TL only	95.771	-0.406	-0.678

2. § 192.743 Pressure limiting and regulating stations: Testing of relief devices

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 15 months, but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to

which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

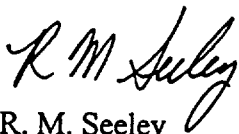
(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

Koch Gateway has failed to perform inspections of the pressure limiting and regulating stations at the Pineland Rual and Magasco compressor stations for 1996 and 1997, to determine that they have enough capacity to limit the pressure on the facilities.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed \$25,000 for each violation for each day the violation persists up to a maximum of \$500,000 for any related series of violations. We have reviewed the circumstances and supporting documentation involved in this case and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violation, we will take enforcement action when and if the continued violation comes to our attention.

Please refer to CPF No. 48111W in any correspondence/communication on this matter.

Sincerely,

A handwritten signature in cursive script, appearing to read "R M Seeley".

R. M. Seeley
Regional Director, Southwest Region

76



U.S. Department
of Transportation
**Research and
Special Programs
Administration**

Southwest Region,
Pipeline Safety

2320 La Branch
Houston, TX 77004

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

October 8, 1998

Mr. Dan Stecklein
Vice President of Operation
Koch Gateway Pipeline Company
P.O. Box 1478
Houston, Texas 77251-1478

RECEIVED
BUREAU OF PIPELINE SAFETY

MAY 05 1999

U.S. DEPARTMENT OF TRANSPORTATION
BUREAU OF PIPELINE SAFETY
HOUSTON, TX

CPF No. 48110-W

Dear Mr. Stecklein:

Between July 27 and 31, 1998, a representative of the Southwest Region, Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of the facilities, operating and maintenance (O&M) procedures manuals and pipeline records of Koch Gateway Pipeline Company in the following area offices: Montpelier; Kenner, Houma, Louisiana (Former Lafayette Division I, and Baton Rouge Area Office).

As a result of the inspection, it appears that you have committed probable violations of the pipeline safety regulations, Title 49, Code of Federal Regulations, Part 192. The probable violations are:

1. **§192.465 (a) External corrosion control: Monitoring:** Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463.

Records were reviewed for your Montpelier location for the Kosciusko 30" transmission system and it was noted that in some locations cathodic potential readings were below the minimum requirement for two consecutive years in 1997 and 1998, the locations were: I-55 casing crossing, Old Spring Creek Road off 1061 casing, 1" Farm Tap, and Tap to Osyka 2" (130-8).

Koch Gateway has failed to perform the required tests of its pipeline systems which are under cathodic protection for 1996 in the Bogalusa area. The locations include: Amite 4", 6", and 8" system from Mile Post 056.230 to 063.660; Covington Area (0.7 mile); Bogalusa 10" lateral, from Mile Post 56.10 to 70.490; St. Joseph Abby on Index 301-04-02-02 about 1.5 miles; Franklinton 4" system, Mile Post 0700 to 1700, about 17 miles.

The operator indicated the inspections for these pipeline locations were done but the records were missing due to the personnel change in various locations.

2. **§192.465 (b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months, to insure that it is operating.**

Koch Gateway has failed to perform inspections in 1996 for the following rectifiers: On Bogalusa 10", rectifiers No. 3518, 1632, 1519, 3631; On Franklinton 4", rectifiers No. 3437, 3529; and on Bogalusa 8", rectifier's No. 3538, 3528, 3530, 3456. The operator indicated the inspections for these rectifiers were done but the records were missing due to the personnel change in various locations.

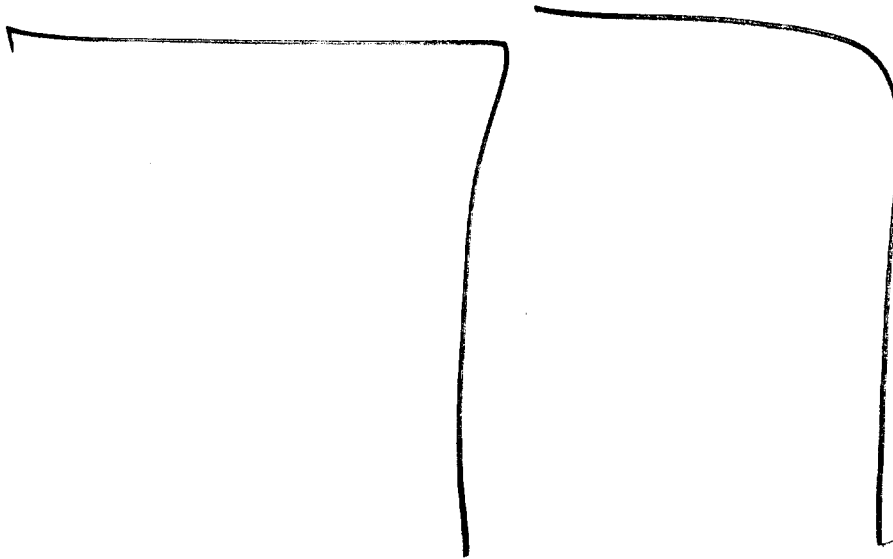
Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed \$25,000 for each violation for each day the violation persists up to a maximum of \$500,000 for any related series of violations. We have reviewed the circumstances and supporting documentation involved in this case and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violation, we will take enforcement action when and if the continued violation comes to our attention.

Please refer to CPF No. 48110W in any correspondence/communication on this matter.

Sincerely,



R. M. Seeley
Regional Director, Southwest Region





U.S. Department
of Transportation

Research and
Special Programs
Administration

Southwest Region,
Office of Pipeline Safety

2320 La Branch, Suite 2100
Houston, TX 77004
(713) 718-3746

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 15, 1999

Mr. Dan Stecklein
Vice President of Operation
Koch Gateway Pipeline Company
P.O. Box 1478
Houston, Texas 77251-1478

RECEIVED
R.R.C. OF TEXAS
APR 19 1999
GAS CORROSION DIVISION
AUSTIN, TX

Dear Mr. Stecklein:

CPF No.49101-W

Between May and October, 1998, a representative of the Southwest Region, Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code, conducted an onsite pipeline safety inspection of the facilities, operating and maintenance (O&M) procedures, manuals and pipeline records of Koch Gateway Pipeline Co (Koch). The inspection included the following divisions: Carthage Division II, Jackson Division, Lafayette Division II, West Lake Area Office, Spring Division III, Carthage Division I, Spring Division I, Spring Division II, Lafayette Division I, and Baton Rouge Area Office.

As a result of the inspection, it appears that you have committed probable violations of the pipeline safety regulations, Title 49, Code of Federal Regulations, Part 192. The probable violations are:

1. **§192.179 Transmission line valves (b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:**
(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

It was noted in a field review of your Longview Area Office that on Index 11-2 at Main Line Block Valve 855 near HW 64, a wooden box was used to protect the valve from tampering and damage. The box door was broken and without a lock and the valve itself was unchained and unlocked. The wooden box door appeared to have been broken for a period of time. Additionally, you had not taken prompt remedial action to correct the problem until our inspector pointed it out.

2. §192.465(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

Records were reviewed in your Longview Area Office and Carthage Division I Office (Shreveport Area). The readings listed below indicate that you have had a problem maintaining adequate potentials on your pipelines for one to three years and you have not taken remedial action to correct some of these deficiencies until after our inspection in 1998.

Location (Longview Area)	Survey Yr. P/S (v)	Survey Yr. P/S (v)	Survey Yr. P/S (v)
	1995	1996	1997
FM 3251- West side VLV #C105E	-1.010	4/96 -0.676	5/97 -0.800 10/97 -0.890
TPL 1-3 Gladewater CG Tap-TU	-0.930	4/96 -0.726	5/97 -0.724 10/97 -0.921
Farm Tap Meter Removed	-1.015	4/96 -0.740	5/97 -0.709 10/97 -0.962
Farm Tap- TF No.52.050	-0.860	4/96 -0.422	5/97 -0.411 10/97 -0.822
Farm Tap- TF No.52.500	-0.920	4/96 -0.587	5/97 -0.521 10/97 -0.892
Blow Off	-0.905	4/96 -0.645	5/97 -0.447 10/97 -1.347
Farm Tap/Two Story House-TF	-1.085	4/96 -0.838	5/97 -0.555 10/97 -0.901
Old Tap W of Oil Road VZ1912	-1.085	3/96 -0.775	5/97 -0.824 10/97 -0.981
TPL 1-26 Edgewood MP 0.01, Entex End- TF	-0.850	4/96 -0.700	5/97 -0.700 10/97 -0.921

Location (Longview Area)	Survey Yr. P/S (v)	Survey Yr. P/S (v)	Survey Yr. P/S (v)
	1995	1996	1997
TPL 1- 27:Grand Saline #2 Tap End Loop-Tu	-1.785	3/96 -0.610	4/97 -0.816 8/97 -1.118
Mid at Pole	-1.250	6/96 -0.823	4/97 -0.627 10/97 -0.890
Seco Crane S Fence	2.375	5/96 -0.624	4/97 -0.577 10/97 1.285
Randol Mill Road	-1.025	6/96 -0.826	6/97 -0.825 9/97 -1.109
Tap on TPL 1 at MP 97.47-TU	-1.786	3/96 -0.721	3/97 -0.823 8/97 -1.103
Grand Saline C.G. Entex-TF	-1.150	3/96 -0.704	6/97 -0.841 10/97 -1.206
Cooks RD Farm Tap- 8" W-TF	-0.793	7/96 -0.715	6/97 -0.826 10/97 -1.130
Meadowbro ok Drive 8" W	-0.717	7/96 -0.785	6/97 -0.642 10/97 -1.160
MeadowBro ok Dr. 12" E	-0.545	7/96 -0.610	6/97 -0.616 10/97 -0.983
TPL-11 at MP 16.05	-0.985	7/96 -0.707	9/97 -0.510
TPL-11 at MP 22.24	-0.598	4/96 -0.625	5/97 -0.611
TPL-11 at MP34.82	-0.647	4/96 -0.625	6/97 -0.680

Location (Longview Area)	Survey Yr. P/S (v)	Survey Yr. P/S (v)	Survey Yr. P/S (v)
Location #	1995	1996	1997
TPL-11 at (TL @ Marker) MP37.00	-1.023	4/96 -0.700	6/97 -0.675
TPL-11 at (Blow Off) MP55.00	-0.914	4/96 -0.535	5/97 -0.914
TPL-430-1 (CR 1105) at MP 0.1	-1.271	7/96 -0.795	7/97 -0.651
TPL-430-1(I-20 NS) at MP 0.36	-1.002	7/96 -0.639	7/97 -0.654
TPL-430-1 (Entex EOL) at MP 1.47	-0.940	7/96 -0.520	7/97 -0.542
TPL-430-1 (Farm Tap) at MP 0.81	-0.965	7/96 -0.604	7/97 -0.601
TPL-430-1(NS HW 80 at MP 3.11	-0.940	7/96 -0.793	7/97 -0.791
TPL-430-1 (Extex EOL) at MP 3.34	-0.920	7/96 -0.867	7/97 -0.821
Location (Carthage Div.I - Shreveport Area)	Survey Yr.P/S (v)	Survey Yr.P/S (v)	Survey Yr.P/S (v)
Location #:	1996	1997	1998
220.360	6/96 -0.670 10/96 -0.900	5/97 -0.500 10/97 -0.865*	6/98 -0.480

Location (Carthage Div.I - Shreveport Area)	Survey Yr.P/S (v)	Survey Yr.P/S (v)	Survey Yr.P/S (v)
Location #:	1996	1997	1998
220.420	6/96 -0.680 10/96 -0.900	5/97 -0.710 10/97 -0.875*	6/98 -0.710 9/98 -0.780**
220.670	3/96 -0.850 10/96 -0.901	5/97 -0.790 10/97 -0.886*	6/98 -0.610
220.880	3/96 -0.710 10/96 -0.900	5/97 -0.690 10/97 -0.900*	6/98 -0.910
221.060	3/96 -0.770 10/96 -0.900	5/97 -0.630 10/97 -0.900*	6/98 -0.630
221.080	3/96 -0.660 10/96 -0.870	5/97 -0.640 10/97 -0.890*	6/98 -0.550
221.800	3/96 -0.870	5/97 -0.650 10/97 -1.00	6/98 -0.770 9/98 -0.870**
224.560	3/96 -0.660	5/97 -0.650 11/97 -1.200*	6/98 -1.140
224.690	3/96 -0.490 10/96 -0.780	5/97 -0.430 11/97 -0.990***	6/98 -0.950

Location (Carthage Div.I - Shreveport Area)	Survey Yr.P/S (v)	Survey Yr.P/S (v)	Survey Yr.P/S (v)
Location #:	1996	1997	1998
226.440	3/96 -0.240 10/96 -1.100	5/97 -0.510 10/97 -1.135*	6/98 -0.550 9/98 -0.508
237.080	3/96 -0.720	6/97 -0.720	6/98 -1.210

* Indicated on operator's records: Retaken after rain.

** The reading was taken during our field inspection in September, 1998.

*** Indicated on operator's records: Retaken after a new ground bed was installed.

3. **§192.481 Atmospheric corrosion control: Monitoring.** After meeting the requirements of §192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipeline, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

It was noted during the field review in your Goodrich Area Office and Longview Area Office that at stream crossings and elsewhere along the pipeline route that atmospheric corrosion has developed on the pipe where it leaves the ground, at the air to ground interface. Specifically, Longview Area Office: Farm Tap W. Side of HWY 110 in Index 11; Goodrich Area Office: MP 136.70, in Index TPL-59, MP 47.000, MP 67.900 in Index TPL-64, MP 32.700 in Index 11-3, etc. These pipelines showed signs of atmospheric corrosion or small holidays and demonstrated a lack of remedial measures for the prevention of atmospheric corrosion. It appeared that the pipelines have been exposed to the atmosphere for some time.

4. **§192.703(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.**

Koch's O&M Procedures state that it uses both driving and flying to inspect the pipeline right-of-way. At the time of the OPS inspections several locations in the maintenance areas listed below had trees, brush and grass overgrowing the right-of-way, preventing Koch personnel from effectively observing surface conditions during the patrols:

- a) Kenner Area: Highway 90 across from the fence surrounding the Moncinto Plant,

b) Houma Area: MP 13.40 at Lake Long St. Rose, MP 1.50 on the Houma Field line, and MP 0.20 on the 2 inch Zapata line,

c) Longview Area: MP 25.50 across from the Arp, Texas city gate, and MP 9.66 at farm tap CR195D-TF,

d) Goodrich Area: MP 38.08 and MP 38.43 on Index 64, and The Bisteneau storage field.

At Highway 90/Montcinto Plant fence the pipeline could not be immediately located ; the pipeline marker was either completely covered with vegetation or there was no marker at the location. Koch has failed to maintain its pipeline facilities so that: a) pipeline patrols can observe all of the right-of-way (§192.705) and b) the location of the pipeline can be identified (§192.707(a)(2)).

Under 49 United States Code, §60122, you are subject to a civil penalty not to exceed \$25,000 for each violation for each day the violation persists up to a maximum of \$500,000 for any related series of violations. We have reviewed the circumstances and supporting documentation involved in this case and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violation, we will take enforcement action when and if the continued violation comes to our attention.

Please refer to CPF No. 49101-W in any correspondence/communication on this matter.

Sincerely,



R. M. Seeley, Director
Southwest Region

cc: Railroad Commission of Texas

78

United States General Accounting Office

GAO

Report to the Ranking Minority Member,
Committee on Commerce,
House of Representatives

May 2000

PIPELINE SAFETY

The Office of Pipeline Safety Is Changing How It Oversees the Pipeline Industry



GAO/RCED-00-128

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Abbreviations

OPS	Office of Pipeline Safety
DOT	Department of Transportation



United States General Accounting Office
Washington, D.C. 20548

Resources, Community, and
Economic Development Division

B-283653

May 15, 2000

The Honorable John D. Dingell
Ranking Minority Member
Committee on Commerce
House of Representatives

Dear Mr. Dingell:

Pipelines are inherently safer to the public than other modes of freight transportation for natural gas and hazardous liquids (such as oil products) because they are, for the most part, located underground. Nevertheless, the volatile nature of these products means that pipeline accidents can have serious consequences. For example, when a pipeline ruptured and spilled about 250,000 gallons of gasoline into a creek in Bellingham, Washington, in June 1999, three people were killed, eight were injured, several buildings were damaged, and the banks of the creek were destroyed along a 1.5-mile section.

The Office of Pipeline Safety, within the Department of Transportation, administers the national regulatory program to ensure the safe transportation of natural gas and hazardous liquids by pipeline. The Office has traditionally carried out its responsibility by issuing minimum standards and enforcing them uniformly across these pipelines. The Accountable Pipeline Safety and Partnership Act of 1996 directed the Office to establish a demonstration program to test a risk management approach to pipeline safety. This approach involves identifying and addressing specific risks faced by individual pipeline companies rather than applying uniform standards regardless of risks. The act allowed the Office to exempt companies in the program from the uniform standards but did not eliminate the standards.

Concerned about the recent accident in Bellingham, you asked us to review the Office's performance in regulating pipeline safety. Accordingly, we examined (1) the extent of major pipeline accidents from 1989 through 1998 (the most recent data available), (2) the Office's implementation of the 1996 act's risk management demonstration program, (3) the Office's inspection and enforcement efforts since the act's implementation, and (4) the Office's responsiveness to recommendations from the National Transportation Safety Board (the Safety Board) and to statutory

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requirements designed to improve pipeline safety. In addition, you asked us to provide information on the current status of the investigation of the accident in Bellingham. This latter information is provided in appendix I.

Results in Brief

From 1989 through 1998, pipeline accidents resulted in an average of about 22 fatalities per year. Fatalities from pipeline accidents are relatively low when compared with those from accidents involving other forms of freight transportation: On average, about 66 people die each year from barge accidents, about 590 from railroad accidents, and about 5,100 from truck accidents. While these statistics provide an indication of the relative safety of pipelines for transporting natural gas and hazardous liquids, the total number of major pipeline accidents (those resulting in a fatality, an injury, or property damage of \$50,000 or more) increased by about 4 percent annually over this 10-year period. Most fatalities and injuries occurred as a result of accidents on pipelines that transport natural gas to homes and businesses (primarily intrastate pipelines), while most property damage occurred as a result of accidents on pipelines transporting hazardous liquids (primarily interstate pipelines). Furthermore, pipelines that transport hazardous liquids account for nearly eight times as many major accidents per mile of pipeline as do pipelines that transport natural gas to homes and businesses. The Office of Pipeline Safety's data on the causes of pipeline accidents are limited to a few categories, but these limited data indicate that damage from outside forces, such as excavation, is the primary cause of such accidents.

The Office has implemented a risk management demonstration program, as the 1996 act requires, and has approved six demonstration projects, which are ongoing. The Office issued guidance on performance measures for the overall program and for individual projects but has not established specific measures of the program's impact on safety, as the act requires. Even though the projects are not complete and their safety benefits have not been quantified, the Office is moving ahead with a risk-based approach to safety regulation based partially on preliminary qualitative results of the program. Specifically, the Office has proposed a rule that would require some companies that operate hazardous liquid pipelines that run through high-risk areas (populated areas, environmentally sensitive areas, and commercially navigable waterways) to implement a program to comprehensively examine pipelines in these areas to identify and address potential risks, including assessing the current condition of their pipelines. The proposed rule will supplement, not replace, the existing minimum standards. The Office also plans to take several actions that are necessary

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to implement the new approach, such as devising a method to review the companies' programs and hiring and training additional staff to conduct the reviews. Office officials estimate that pipeline companies will develop plans for assessing the condition of their pipelines by September 2001 and that the assessments will be complete by September 2007. While we agree that a risk management approach offers the potential to improve pipeline safety, several critical steps—such as issuing a final rule and hiring staff—must be completed before the Office can implement such an approach.

Since the act's implementation, the Office has modified its inspection and enforcement approach. With respect to inspections, it has moved toward inspecting entire pipelines rather than segments of pipelines. Since 1996, the Office has decreased its use of "unit" inspections—inspections of individual pipeline segments—and has begun inspecting companies' entire pipeline operating systems at one time to provide more comprehensive assessments of safety risks. As a result, the Office has reduced its reliance on states to inspect interstate pipelines because it is difficult to coordinate participation by individual states in systemwide inspections. However, state pipeline safety officials who currently inspect interstate pipelines for the Office are concerned that their diminishing role has resulted in fewer and less thorough inspections of pipelines. The Office has also revised its enforcement of compliance with regulations by reducing its use of fines and, instead, working with operators to identify and correct safety problems. From 1990 to 1998, the Office decreased the proportion of enforcement actions in which it proposed fines from about 49 percent to about 4 percent. Some state safety regulators agree with this strategy; others do not. We are recommending that the Secretary of Transportation direct the Office to work with states to determine how state inspectors could be used to more effectively oversee pipeline safety and evaluate the effectiveness of its strategy of reducing the use of fines.

The Office's responsiveness to the Safety Board's recommendations and statutory requirements has been mixed. The Office has historically had the lowest rate of implementation for these recommendations of any transportation agency and has not implemented 22 statutory requirements, 12 of which date from 1992 or earlier. It has not implemented some of the recommendations and requirements because it believes they would be too costly for the pipeline industry compared with the expected benefits. However, according to the Safety Board, some of the Office's analyses of costs and benefits are flawed because the Office did not consider all of the benefits. The Office has recently taken action on some issues covered by outstanding recommendations and requirements, such as identifying

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countermeasures for preventing damage to pipelines from excavation and requiring pipeline operators to inspect their pipelines for corrosion. Safety Board officials say they are encouraged by these recent efforts but note that some of the Office's actions are incomplete and may not fully address the Safety Board's recommendations.

Background

Pipelines transport the bulk of natural gas and hazardous liquids (such as oil products) in the United States.¹ Specifically, pipelines carry nearly all of the natural gas and about 65 percent of the crude oil and refined oil products. Three primary types of pipelines form a network of nearly 2.2 million miles.

- Natural gas transmission pipelines transport natural gas over long distances from sources to communities. These pipelines—about 325,000 miles—are primarily interstate.
- Natural gas distribution pipelines continue to transport natural gas from transmission pipelines to residential, commercial, and industrial customers. These pipelines—about 1.7 million miles—are primarily intrastate.
- Hazardous liquid pipelines transport crude oil to refineries and continue to transport the refined oil product, such as gasoline, to product terminals and airports. These pipelines—about 156,000 miles—are primarily interstate.

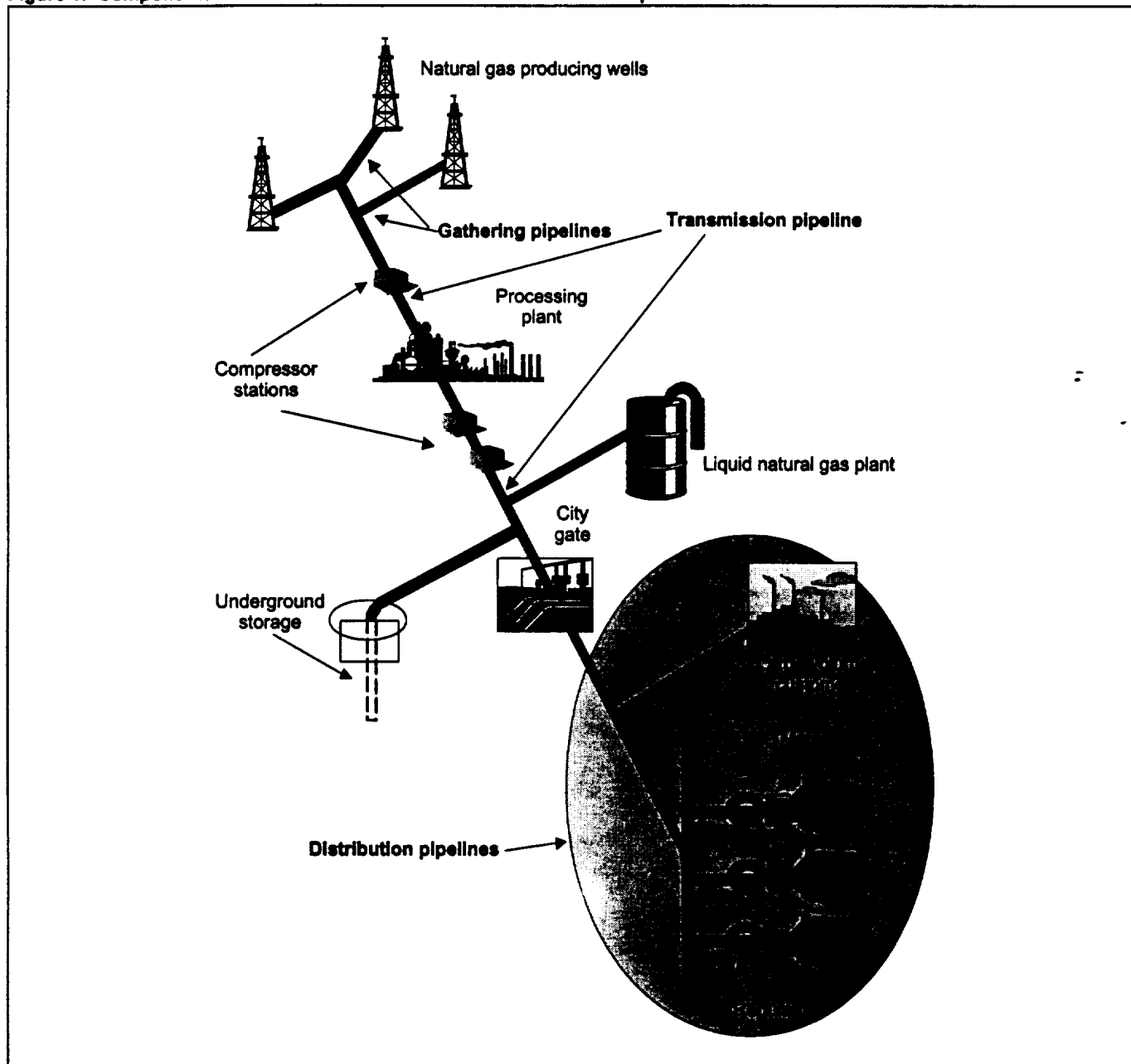
In addition, pipelines include several components that aid in the collection and transportation of products. (See fig. 1.) For example, gathering pipelines collect natural gas or crude oil from producing wells and carry the product to a natural gas transmission or hazardous liquid pipeline.² Compressor stations (for gas) and pumping stations (for liquids) keep the product flowing smoothly.

¹Hazardous liquid pipelines carry products such as crude oil, diesel fuel, gasoline, jet fuel, anhydrous ammonia, and carbon dioxide.

²Some gathering lines and segments of gathering lines in rural areas are excluded from federal pipeline safety regulation. The Office is developing a definition of natural gas gathering lines that may result in the regulation of some rural gathering lines. The mileage statistics above include gathering lines that are subject to federal regulation.

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Figure 1: Components of Natural Gas Transmission and Distribution Pipelines



Source: Office of Pipeline Safety.

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The extensive network of natural gas transmission and hazardous liquid pipelines appears in appendix II.³

Several federal and state agencies have roles in pipeline safety. The Office of Pipeline Safety (OPS) develops, issues, and enforces pipeline safety regulations for natural gas and hazardous liquid pipelines. These regulations contain minimum safety standards that the pipeline companies that transport these products must meet for the design, construction, inspection, testing, operation, and maintenance of pipelines. OPS' fiscal year 2000 budget is about \$37 million, funded primarily from industry user fees. In fiscal year 1999, OPS employed 105 people, 51 of whom were pipeline inspectors.

In general, OPS retains full responsibility for inspecting and enforcing regulations on interstate pipelines but certifies states to perform these functions for intrastate pipelines. Certified states are allowed to impose safety requirements for intrastate pipelines that are stricter than the federal regulations. As of March 2000, 47 state agencies, the District of Columbia, and Puerto Rico were certified for intrastate natural gas pipeline inspections, and 12 state agencies were certified for intrastate hazardous liquid pipeline inspections.⁴ Certified states are authorized to receive reimbursement of up to 50 percent of the costs of their pipeline safety programs from OPS. In fiscal year 1999, these states received about \$13 million from OPS in state pipeline safety grants, or an average of about 44 percent of their estimated budgets. In fiscal year 1998, the states employed about 300 pipeline inspectors.

OPS also uses some states to help inspect interstate pipelines. These states, or "interstate agents," inspect segments of interstate pipelines within their boundaries. However, OPS handles any enforcement actions identified through inspections conducted by these interstate agents. As of March 2000, eight states were acting as interstate agents—five states for natural gas pipelines, one state for hazardous liquid pipelines, and two states for both types of pipelines. These states do not receive additional federal funds for inspecting interstate pipelines.

³No map is available for the natural gas distribution pipeline network, which is too extensive to map because it is located in populated areas.

⁴In addition, four state agencies—Delaware for natural gas and Kentucky, New Mexico, and South Carolina for hazardous liquid—have agreements with OPS to inspect intrastate pipelines, but OPS handles any enforcement actions.

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Other federal agencies, such as the Minerals Management Service within the Department of the Interior and the Environmental Protection Agency, also have some regulatory authority related to pipeline safety. The Minerals Management Service has jurisdiction over producer-operated oil pipelines on the Outer Continental Shelf. The Environmental Protection Agency regulates tanks used to store hazardous liquids or transfer them to or from other modes of transportation. In contrast, OPS regulates storage tanks used to store hazardous liquids for continued transportation by pipeline at a later date or to relieve surges in the pipeline system. A single storage tank or a facility with multiple tanks may have uses that fall under the authority of both the Environmental Protection Agency and OPS. As of April 2000, the agencies were working to clarify the circumstances under which each agency has authority.

The National Transportation Safety Board investigates transportation accidents, including significant pipeline accidents (such as those involving fatalities). On the basis of these investigations, the Safety Board issues recommendations to OPS and other federal agencies aimed at preventing future accidents. Finally, several federal statutes enacted since 1988 contain requirements designed to improve pipeline safety and enhance OPS' ability to oversee the pipeline industry. Many of these requirements address the same issues as the Safety Board's recommendations.

Pipelines Are Relatively Safe, but the Number of Major Accidents Increased From 1989 Through 1998

Pipelines have an inherent safety advantage over other modes of freight transportation because they are primarily located underground, away from public contact. From 1989 through 1998, pipeline accidents resulted in an average of about 22 fatalities per year, compared with about 66 from barge accidents, about 590 from railroad accidents, and about 5,100 from large truck accidents.⁵ A 1999 study comparing modes of oil transportation from 1992 through 1997—pipeline, rail, tank ship, barge, and truck—found that the likelihood of fatality, injury, or fire and/or explosion is generally lowest for pipelines.⁶ The rate of fatalities, injuries, and fires/explosions per ton-mile of oil transported for all other modes is typically at least twice—and in

⁵In its regulations, OPS refers to the release of natural gas from a pipeline as an "incident" and a spill from a hazardous liquid pipeline as an "accident." For simplicity, this report will refer to both as "accidents."

⁶Cheryl J. Trench, *The U.S. Oil Pipeline Industry's Safety Performance*, Allegheny Energy Group report prepared for the Association of Oil Pipelines and the American Petroleum Institute (May 1999) (Rev.).

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some cases more than 10 times—as great as the rate for pipelines. (See table 1.)

Table 1: Relative Occurrence of Transportation Accidents Per Ton-Mile of Oil Transported, 1992-97

Event	Pipeline ^a	Rail	Tank ship	Barge	Truck
Fatality	1.0	2.7	4.0	10.2	87.3
Injury	1.0	2.6	0.7	0.9	2.3
Fire/explosion	1.0	8.6	1.2	4.0	34.7

^aThe rates of occurrence are based on a value of 1.0 for pipeline. Values of less than 1.0 indicate a better safety record.

Source: Association of Oil Pipelines.

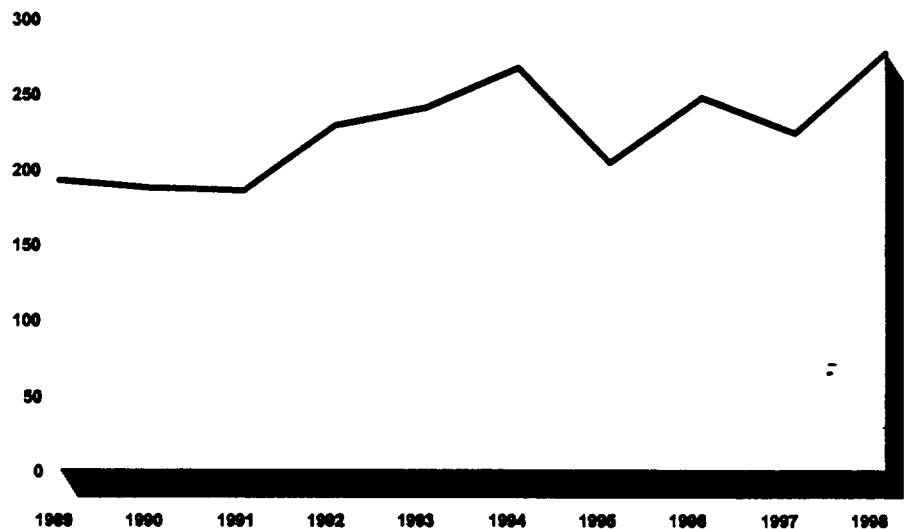
While pipelines are relatively safe compared with other transportation modes, the number of major pipeline accidents increased overall from 1989 through 1998.⁷ In total, there were 2,241 major accidents (those causing a fatality, an injury, or more than \$50,000 in property damage) during this period. Although the number of major accidents varied from year to year, these accidents increased by approximately 4 percent annually.⁸ (See fig. 2.) According to OPS officials, the increase in major accidents over this period can be attributed to a 10-percent overall increase in pipeline mileage, growth in the volume of products transported by pipelines (due to an increase in the nation's energy consumption), and population growth near pipelines.

⁷All natural gas and hazardous liquid pipeline operators are required to report accidents that result in a fatality, an injury, or \$50,000 or more in property damage (which this report defines as "major"). In addition, natural gas pipeline operators are required to report events that result in an emergency shutdown of a liquefied natural gas facility and may report any accident they consider "significant," even if it does not meet any reporting threshold. Furthermore, hazardous liquid operators are required to report any accident that results in an explosion or a fire, the release of 50 or more barrels of hazardous liquid or carbon dioxide, or the escape into the atmosphere of more than 5 barrels per day of highly volatile liquids. There were 1,801 accidents from 1989 through 1998 that did not meet the definition of a major accident.

⁸The total number of accidents, major and nonmajor, reported to OPS decreased by about 1.5 percent annually over this period.

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Figure 2: Number of Pipeline Accidents Resulting In Fatalities, Injuries, and/or \$50,000 or More In Property Damage, 1989-98



Source: GAO's analysis of OPS' data.

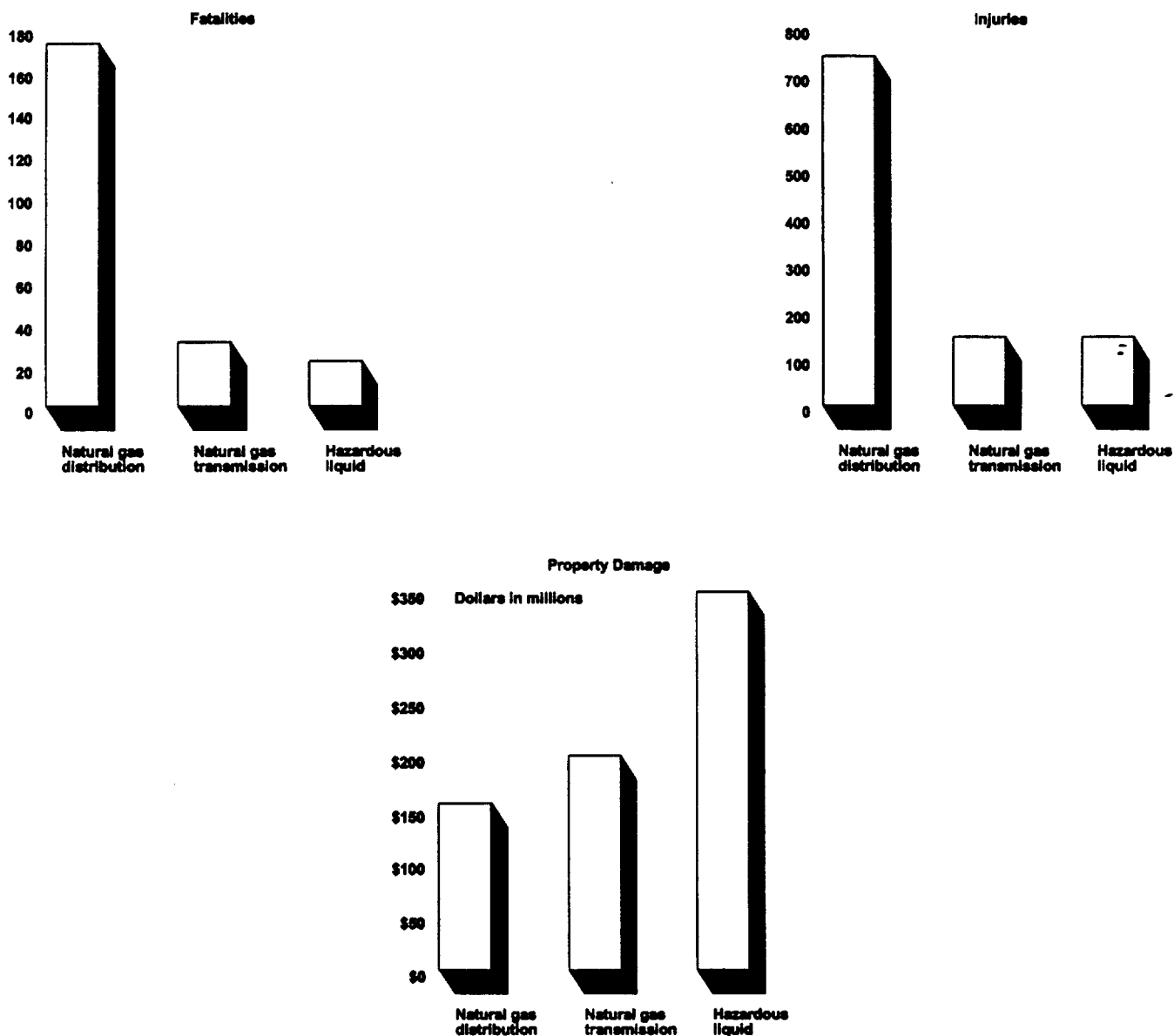
From 1989 through 1998, 226 people died and 1,030 people were injured in major pipeline accidents.⁹ (See fig. 3.) Accidents on natural gas distribution pipelines (which are primarily intrastate) accounted for 173—or 77 percent—of the fatalities and 743—or 72 percent—of the injuries from 1989 through 1998. Because these pipelines are primarily located in populous areas, it is not surprising that accidents on them affect humans more than accidents on other types of pipelines. In addition, major pipeline accidents caused about \$700 million in property damage. From 1989 through 1998, hazardous liquid pipelines (which are primarily interstate) accounted for about \$350 million, or 50 percent, of this property damage

⁹This figure does not include the injuries that occurred during one series of accidents caused by severe flooding near Houston, Texas, in Oct. 1994. We excluded these injuries because OPS' and the Safety Board's data disagree on the number of people injured. OPS' data indicate 1,851 injuries, while the Safety Board reported that a total of 547 persons were treated, primarily for smoke and vapor inhalation. We also excluded this accident from our analysis because we could not determine to what extent the injuries were the result of explosions of petroleum and petroleum products released from the ruptured pipelines or of the controlled burn of these products by the spill response team.

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because the liquids do not dissipate into the atmosphere, as does natural gas.

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Figure 3: Number of Fatalities and Injuries and Amount of Property Damage From Pipeline Accidents, 1989-98

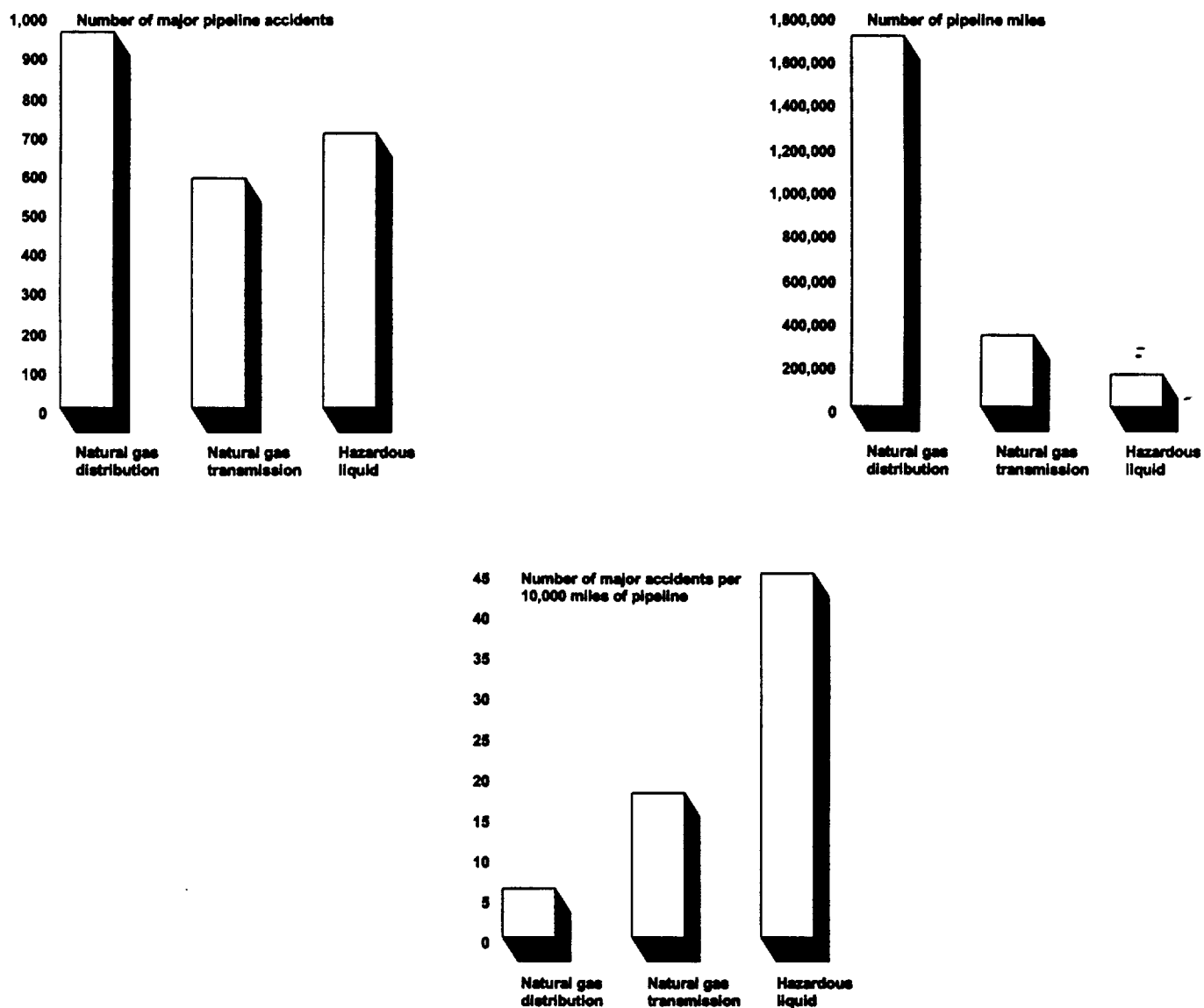
Source: GAO's analysis of OPS' data.

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Representatives from environmental groups believe that property damage from pipeline accidents is understated because not all damage to the environment may be reported to OPS by pipeline operators. For example, over 1.5 million barrels of hazardous liquids—primarily crude oil and gasoline—were spilled from pipelines as a result of all pipeline accidents reported to OPS. However, the total amount spilled from pipelines and, thus, the environmental damage, is actually greater because OPS does not require pipeline operators to report spills of less than 50 barrels. Although there is no complete source of information on these smaller spills, the Environmental Protection Agency maintains data on oil pipeline spills in areas where such spills could cause pollution to navigable waters. These data show that more than 16,000 spills of less than 50 barrels occurred from 1989 through 1998.

Of the major pipeline accidents occurring from 1989 through 1998, most—about 43 percent—occurred on natural gas distribution pipelines. These pipelines also account for the majority of pipeline mileage. However, hazardous liquid pipelines, which account for the smallest portion of total pipeline mileage, have nearly eight times as many major accidents per mile of pipeline as do natural gas distribution pipelines. (See fig. 4.)

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Figure 4: Number of Major Pipeline Accidents, Miles, and Major Accidents per 10,000 Miles of Pipeline, 1989-98

Source: GAO's analysis of OPS' data.

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OPS does not collect comprehensive information on the causes of pipeline accidents. However, OPS' available data indicate that the primary cause of pipeline accidents from 1989 through 1998 was damage from external forces, such as an outside party digging near a pipeline or a natural force like an earthquake or a landslide. These data are limited because OPS uses only five categories of causes for accidents on natural gas distribution pipelines, four categories for those on natural gas transmission pipelines, and seven categories for those on hazardous liquid pipelines. As a result, a large proportion of accidents are attributed to "other causes" that range from failed gaskets or seals to faulty valves. According to these data, from 1989 through 1998, the three most prevalent causes of pipeline accidents were damage from outside forces (45 percent), "other" (25 percent), and corrosion of the pipe (15 percent).

Although Benefits of Demonstration Program Have Not Been Quantified, OPS Is Moving Ahead With a New Regulatory Approach

As a result of the Accountable Pipeline Safety and Partnership Act of 1996, OPS has implemented a risk management demonstration program to investigate whether formalized risk management programs for individual pipeline companies can provide an alternative to the current regulatory approach and achieve a superior level of safety and environmental protection.¹⁰ However, OPS has not established performance measures for the program's impact on safety, as required by the act. OPS maintains that the ongoing program has already produced some qualitative improvements, such as directing resources to the areas posing the greatest safety risks. Partially as a result of its experience with the demonstration program, OPS has proposed a rule that would require some companies that operate hazardous liquid pipelines that run through populated areas, environmentally sensitive areas, or commercially navigable waterways to implement a program to comprehensively examine pipelines in these areas to identify and address potential risks.

¹⁰The act also required, among other things, that OPS conduct risk assessments when prescribing new regulations. In addition to identifying the costs and benefits of the new regulation, OPS must identify the regulatory and nonregulatory options considered, explain its reasons for choosing the selected option instead of the others, and identify the information on which the risk assessment and selected option are based. The status of OPS' actions on these additional requirements is included in app. IV.

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**Risk Management
Demonstration Program
Was Designed to Show
Benefits of Going Beyond
Minimum Regulatory
Standards**

The 1996 act, together with a presidential memorandum to the Secretary of Transportation, requires OPS to evaluate, through a demonstration program, whether a risk management approach to pipeline safety can achieve a level of safety and environmental protection that is greater than the level achievable through compliance with the current pipeline safety regulations.¹¹ The current regulations establish minimum safety requirements for all pipeline companies, such as a requirement for a protective coating on all pipelines to mitigate corrosion. A risk management approach goes beyond the minimum requirements by identifying and focusing resources on risks to individual pipelines that may not be fully addressed in the regulations. For example, identifying emergency response capability as a risk and subsequently developing an electronic system that would notify emergency officials of a pipeline leak or rupture would exceed current regulations.

The act further required OPS to develop performance measures for the program to evaluate its safety and environmental benefits. The act also authorized OPS to exempt companies participating in these projects from all or a portion of the existing regulations.¹² Finally, the act required OPS to report by March 31, 2000, on the results of the demonstration program, including its safety and environmental benefits.

To address the requirement for demonstrating an improved level of safety and environmental benefits, OPS issued guidance that identified superior safety, environmental protection, and service reliability as one of three primary objectives for the program. The guidance also identified increased efficiency of pipeline operations and improved communication among industry, government, and other stakeholders as two additional primary objectives. To measure progress toward these objectives, the guidance

¹¹The 1996 act contained no limitation on the number of demonstration projects and required that risk management plans be designed to achieve a level of safety equivalent to or greater than the level that would otherwise be achieved. However, when signing the 1996 act, the President directed the Secretary of Transportation to limit the number of projects to 10 and to ensure that the projects demonstrate superior, not just equal, safety and environmental benefits.

¹²One company that operates a natural gas pipeline has received an exemption from the current regulations. If the population density increases near a pipeline, the current regulations require the pipeline company to install a thicker-walled pipe or reduce the operating pressure. In exchange for the exemption from this requirement, OPS is requiring the company to take additional precautions, such as conducting internal inspections of the pipelines in these areas, while maintaining the existing pipe at the original pressure.

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describes potential programwide measures, such as accident data, risk awareness, and customer service. The guidance also recognizes the need for project-specific measures intended to document starting conditions, changes during the program, and expected outcomes for each project. According to the guidance, the project-specific measures were to be developed by the pipeline operators before the projects were approved by OPS.

As of January 2000, OPS had approved six projects for the program. The projects vary in scope, ranging from examining the risks associated with excavation work on a single pipeline at one company, to a comprehensive risk management plan designed to assess all risks associated with the operation of two multistate pipeline systems owned by another company. (App. III provides more details on the individual projects and the program's overall costs.)

OPS Has Not Measured Benefits of Risk Management Demonstration Program

OPS has not complied with the act's requirements or its own guidance on developing performance measures for the risk management demonstration program. Specifically, OPS has not developed programwide measures and has approved five of the six demonstration projects without project-specific measures in place, even though OPS' guidance required pipeline operators to develop such measures before the agency would approve a project. OPS officials and representatives of participating companies told us that they have been unable to develop performance measures because the impact on safety cannot easily be isolated from the effects of other safety activities outside the program, especially given the relatively short duration of the program. For example, an increase in the number of defects found over a period of years may indicate a growing risk of pipeline failure, or it may reflect the results of targeting inspections to identify weaknesses or of introducing new technologies to detect defects. In addition, OPS officials told us that the measures have been difficult to develop because the participating companies have unique pipeline systems and the demonstration projects involve different aspects of the systems. Moreover, according to the officials, many companies are not collecting the types of data necessary to support an evaluation of the program's overall impact on safety.

Only one program participant, Phillips Pipe Line, has developed performance measures and generated data for its project. According to OPS officials, this project is limited in scope and has thus far generated

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little data. The other participants are trying to develop performance measures for their projects.

While OPS has not developed any programwide or project-specific measures to evaluate the program's performance, OPS officials told us that the program has yielded many qualitative benefits related to its three objectives. For example, each company is performing safety activities that exceed the requirements in the current regulations, such as conducting periodic internal inspections of pipelines and installing additional valves to prevent hazardous liquids from flowing into rivers. Officials with one company said that the company has allocated its resources more effectively by using a risk-based computer model to develop funding priorities for its valve modification and replacement efforts. To improve communication and information flow, two companies have conducted "hands-on" workshops for OPS, and another company is developing a computerized method of exchanging information with OPS.

Although the act required OPS to issue a report on the results of the demonstration program in March 2000, OPS plans to issue a report in spring 2000 on the progress of the program. OPS officials do not know when the program will be complete. According to OPS officials, the projects took longer to implement than planned because, among other things, (1) the participating companies did not already have vigorous, formalized risk management programs in place; (2) OPS took longer than expected to review and approve individual projects; and (3) several of the applicant companies underwent corporate mergers that created uncertainties about whether the companies would continue to participate in the program.

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OPS Is Moving to Implement Risk Management Into Its Regulatory Framework

Even though the demonstration program is still ongoing and its safety and environmental benefits have not yet been quantified, OPS has proposed a rule that draws, in part, on the agency's experiences with the demonstration program to incorporate the use of a risk management approach in pipeline safety regulations.¹³ The proposed rule would affect hazardous liquid pipeline companies (companies that operate systems of 500 miles or more) that have pipelines in "high-consequence areas." The rule defines these areas as populated areas, environmentally sensitive areas, or commercially navigable waterways.¹⁴ OPS estimates that the rule would apply to 66 pipeline companies that operate about 87 percent of the nation's hazardous liquid pipeline mileage. All pipeline operators would still be required to follow the current minimum regulations.

Companies affected by this rule would be required to develop an "integrity management program" to comprehensively examine pipelines in high-consequence areas to identify and address potential risks. Such a program would include, among other things, (1) a plan for assessing the condition of pipelines in these areas, (2) periodic reassessments of the pipelines, (3) criteria for repairing deficiencies discovered through the assessments, and (4) measures of the program's effectiveness. Methods to assess the condition of the pipelines include internal inspections using "smart pigs" (devices that can travel through the pipelines to detect flaws) and hydrostatic testing (draining the pipeline, filling it with water, and increasing the pressure within the pipeline to identify weak points).

OPS intends to review companies' integrity management programs, including the risks identified by the companies and their strategies for addressing the risks. Although OPS officials have not determined exactly how these reviews will be integrated into the agency's periodic inspections of pipeline companies, they told us the reviews would require additional personnel. OPS officials could not estimate how many additional staff would eventually be needed. The agency has requested four additional staff

¹³The proposed rule also draws on the agency's experiences in inspecting pipeline companies' entire operating systems (described in the next section), investigating accidents, and conducting system integrity initiatives.

¹⁴According to OPS officials, the initial rule would affect operators of large hazardous liquid pipeline systems because OPS has gained familiarity with their operations through the risk management demonstration program. Subsequent rules would affect operators of small hazardous liquid pipelines and natural gas transmission pipelines in high-consequence areas.

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for fiscal year 2001, and OPS officials expect to request more in future years. In addition, agency officials told us that OPS is considering hiring contractors to assist with these reviews.

Several actions must occur before OPS can fully implement this new approach to regulating pipeline safety. OPS issued a proposed rule on April 24, 2000, and must incorporate comments from the industry and the public in a final rule. OPS must also complete another rule on the definition of areas that are unusually sensitive to environmental damage before it can identify high-consequence areas.¹⁵ In addition, OPS must develop guidelines for reviewing companies' integrity management programs and hire and train the additional staff needed to conduct the reviews. Meanwhile, the companies that have pipelines in high-consequence areas must develop their programs and assess the current condition of their pipelines. OPS estimates that pipeline companies will develop plans for assessing the condition of their pipelines by September 2001 and that the assessments will be complete by September 2007. (See table 2.)

Table 2: Milestones for Implementing a Risk Management Approach for Regulating Large Hazardous Liquid Pipelines

Date	Action
April 2000	OPS issued a proposed rule requiring enhanced protection of high-consequence areas
October 2000	OPS issues the final rule
Beginning October 2000	OPS hires and trains additional staff to review companies' integrity management programs
December 2000	OPS completes the final rule on the definition of areas unusually sensitive to environmental damage and makes mapping information available to pipeline companies on the Internet
September 2001	Pipeline companies complete plans for assessing the condition of pipelines
September 2004	Individual companies' assessments are 50 percent complete
September 2007	Assessments are 100 percent complete

Source: GAO's analysis of OPS' data.

¹⁵OPS issued a proposed rule on the definition of areas unusually sensitive to environmental damage on Dec. 30, 1999. Comments on the proposed rule are due by June 27, 2000.

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While we agree that a risk management approach offers the potential to improve pipeline safety, we believe that OPS' proposed rule to broadly implement it is not supported by quantifiable evidence (intended to be obtained through the demonstration program) that such an approach has led—or could lead—to a higher level of safety and environmental protection. In addition, OPS plans to require performance measures for pipeline companies' integrity management programs, even though OPS and pipeline operators were not able to develop such measures for the risk management demonstration program. Nevertheless, the rulemaking process could give the safety community, the regulated industry, and affected states and communities the opportunity to shape the final rule so as to establish evidence of the approach's impact on safety and provide for reporting on outcomes and periodic assessments of its effectiveness.

OPS Is Changing How It Inspects Pipelines and Enforces Compliance With Regulations

OPS is moving toward inspecting entire pipelines rather than segments of pipelines and is reducing its reliance on fines to enforce compliance with its regulations. Since 1996, OPS has conducted 10 "systemwide inspections" to identify safety risks to companies' entire pipeline systems. These inspections require more time and resources per inspection than OPS' traditional approach, which is based on inspecting segments or "units" of pipelines. Partly because it was emphasizing systemwide inspections, OPS reduced the number of unit inspections by 47 percent from 1996 through 1999. Also as a result of systemwide inspections, OPS has decreased its reliance on state regulators to inspect interstate pipelines because the agency prefers to use a team of federal inspectors to conduct the systemwide inspections rather than coordinate the activities of federal inspectors and inspectors from multiple states. However, some state regulators are concerned that their diminishing role has resulted in fewer and less thorough inspections.

For enforcement, OPS has been decreasing its use of fines for pipeline companies' violations of safety regulations since before the 1996 act. From 1990 through 1998, OPS' use of fines decreased from 49 percent of total enforcement actions to 4 percent. According to OPS officials, this strategy allows them to focus their efforts and the companies' resources on correcting problems, but they have not evaluated whether their reduced reliance on fines is effective in achieving compliance with regulations.

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OPS Is Changing Its Inspection Approach to Focus on Entire Pipeline Systems

Traditionally, OPS has inspected pipeline companies by conducting "unit inspections"—a checklist approach verifying that an individual operating unit of a company's entire pipeline system is in compliance with pipeline safety regulations. A unit inspection is generally conducted by one OPS inspector in about 3 days. Instead of relying primarily on a unit-by-unit approach to inspections, OPS is now inspecting pipelines through "systemwide inspections"—reviewing all of a company's related operating units at once. Because systemwide inspections can cover hundreds of miles of pipeline in various regions of the country, OPS uses a team of inspectors from all OPS regions that contain part of the operator's system to inspect all of the operating units. According to OPS officials, a systemwide inspection is the equivalent of multiple unit inspections. OPS conducted six systemwide inspections in 1998 and four in 1999; it plans to conduct eight in 2000.

According to OPS officials, systemwide inspections provide a better assessment of the potential safety risks to pipelines than do unit inspections because systemwide inspections can uncover problems that unit inspections would not identify. For example, according to OPS officials, one pipeline company did not coordinate its corrosion prevention activities with information it was obtaining from another part of the company on external damage. Such damage—e.g., a nick in a pipeline's protective coating—can lead to corrosion. During a systemwide inspection, OPS identified this lack of communication as a potential threat to the pipeline's safety.

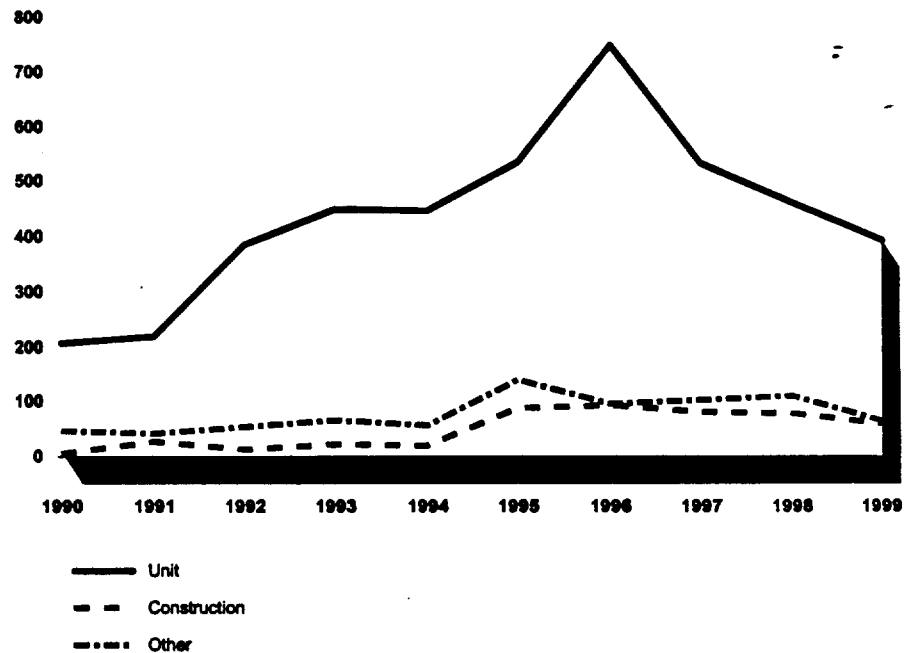
Besides moving to systemwide inspections, OPS is spending more time on construction inspections to reduce the risk that defects will be built into pipelines during construction. Construction inspections also involve more OPS resources than do unit inspections because months may be needed to build a pipeline and inspectors must review plans and observe crucial points in the construction. Since 1995, both the number of pipeline construction inspections and the time OPS inspectors have spent on such inspections have increased. In 1999, OPS inspectors spent 546 days on 65 construction inspections, compared with 102 days on 30 inspections in 1995.

As a result of its change in inspection philosophy, OPS is conducting fewer unit inspections. The number of unit inspections conducted by OPS decreased by 47 percent from 1996 through 1999. (See fig. 5.) (The number of inspections increased sharply during 1995 and 1996 because additional inspectors were hired during that period; since that time, the staffing has

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remained level.) According to OPS officials, this decrease is due to the increased emphasis on systemwide and construction inspections, as well as an increase in the number of accident investigations and in the resources devoted to risk management projects. In addition, OPS officials told us that each unit inspection now takes more time than it did in the past because the agency has modified its inspection form to obtain more in-depth information on how the pipeline company is ensuring the pipeline's safety. For example, the new form requires the inspector to evaluate the overall quality of the operator's corrosion-control program.

Figure 5: OPS' Inspection Activity, by Type of Inspection, 1990-99



Note: "Other" includes failure investigations, complaint investigations, and systemwide inspections.
Source: GAO's analysis of OPS' data.

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Also as a result of its change in inspection philosophy, OPS is relying less on states to inspect interstate pipelines. Although OPS is responsible for inspecting these pipelines, it certified some states to act as interstate agents in the early 1980s because it did not have enough inspection resources. From 1990 through 1994, about 12 interstate agents conducted between 20 and 26 percent of all interstate inspections. In 1995 and 1996, OPS hired additional inspectors and started taking back responsibility for these inspections. By 1999, only 8 percent of all interstate inspections were conducted by 10 interstate agents. In December 1999, OPS canceled its interstate agent agreements with Arizona and Nevada, leaving eight interstate agents—California, Connecticut, Iowa, Michigan, Minnesota, New York, Ohio, and West Virginia.¹⁸

According to OPS officials, the state agencies have performed well as interstate agents, but it is difficult to coordinate inspections by interstate agents—each responsible for the portion of a multistate pipeline system within its own borders—into a systemwide inspection. Rather than coordinating the activities of federal and state inspectors, OPS prefers to use a team of federal inspectors to conduct a systemwide inspection. In addition, OPS officials told us that devoting less time to their responsibilities as interstate agents would allow the states to focus their efforts on intrastate distribution pipelines, where most fatalities from pipeline accidents occur.

Some state officials do not agree with OPS' decision to eliminate interstate agents because they are concerned about its impact on safety. Even though interstate agents do not receive additional federal funds for inspecting interstate pipelines, officials from these states prefer to inspect these pipelines because it allows them to oversee the safety of all pipelines within their boundaries. Some current and prior interstate agents we contacted told us that they inspect operators more frequently than OPS—generally once every year compared with once every 1 to 4 years for OPS—and spend 2 to 4 times longer performing the inspections than does OPS. According to these officials, more frequent and more thorough inspections improve their ability to detect safety problems.

¹⁸In Mar. 2000, OPS proposed an agreement with the state of Washington involving the inspection of interstate pipelines, but, according to OPS officials, the state will not be an interstate agent.

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In addition, some state officials are concerned that because OPS schedules all of its inspections in advance, some violations could go undiscovered. For example, a Connecticut pipeline safety official told us that the state's no-notice inspections on intrastate construction projects have discovered three times as many violations as advance-notice inspections. (According to an OPS official, OPS notifies the companies of the anticipated date of inspections so the companies can have the appropriate manuals and representatives available, but it does not tell the companies which portions of the pipelines will be examined.)

The Department of Transportation (DOT) has proposed legislation to reauthorize the pipeline safety program.¹⁷ Among other things, this legislation would increase the ability of states to participate in the oversight of interstate pipeline transportation (including new construction inspections or accident investigations) and funding for these activities.

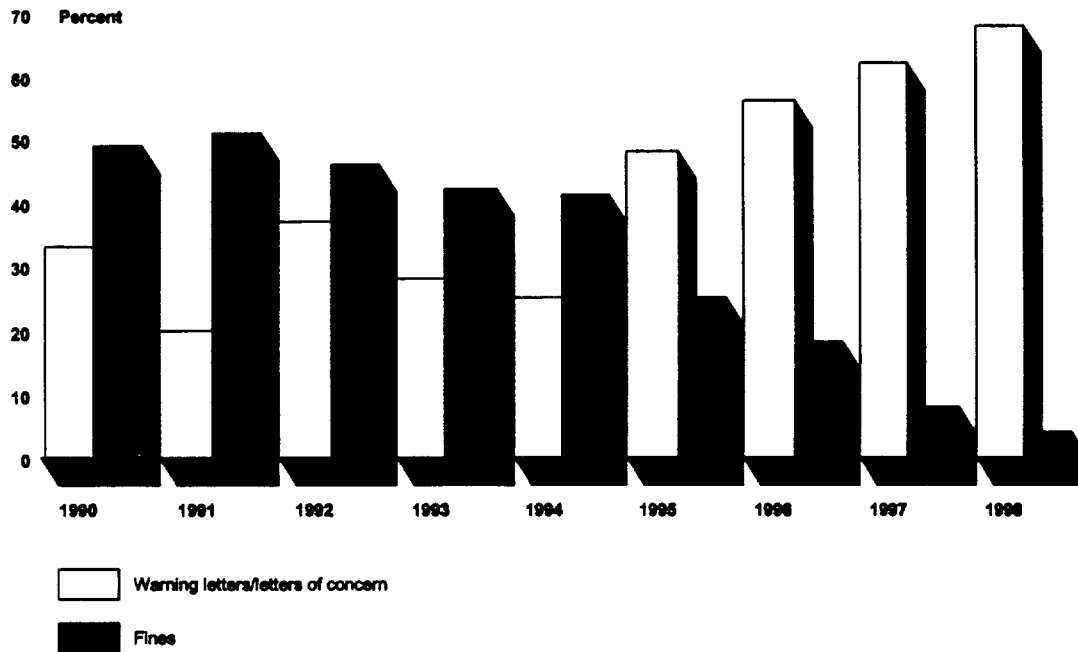
OPS Is Decreasing the Use of Fines for Violations

Since 1990, OPS has decreased its use of fines and increased its use of less severe corrective actions. According to OPS officials, this strategy allows them to work more constructively with companies to address problems. For example, instead of issuing a fine, OPS required a pipeline operator to hydrostatically test 350 miles of pipeline following an accident in 1993. The test revealed seven additional areas that were susceptible to future leaks. Fines are reserved for severe violations, such as those that have resulted in fatalities or substantial environmental damage, or for failures to address problems previously identified by OPS. OPS has not assessed the impact of this approach on safety.

The number of enforcement actions OPS has taken increased from 94 in 1990 to 218 in 1998—a 132-percent increase. However, OPS has also decreased the proportion of enforcement actions in which it proposed fines from about 49 percent in 1990 to about 4 percent in 1998. During this time, it increased the proportion of warning letters and letters of concern that are used to inform pipeline companies of probable violations of safety regulations or other pipeline safety risks but do not assess a fine. The proportion of enforcement actions in which these letters were sent increased from about 33 percent in 1990 to about 68 percent in 1998. (See fig. 6.)

¹⁷The Pipeline Safety and Community Protection Act of 2000 was introduced in the Senate on Apr. 12, 2000 (S. 2409) and the House on Apr. 13, 2000 (H.R. 4276).

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Figure 6: Warning Letters/Letters of Concern and Fines as Percentages of Total Enforcement Actions, 1990-98

Note: The percentages for letters and fines do not add to 100 percent because OPS also uses other enforcement actions, such as compliance orders, to specify the actions a company must take to correct a violation. In addition, an enforcement action may include multiple actions, such as a fine and a compliance order.

Source: GAO's analysis of OPS' data.

According to OPS officials, the proportion of warning letters and letters of concern has increased because letters are now used to inform companies not only of compliance problems, but also of "best practices" that OPS believes would improve the safety of the companies' pipelines. These officials told us that the agency also relies heavily on other enforcement actions that do not involve fines, such as compliance orders requiring pipeline companies to take action to correct safety violations. However, OPS officials were not able to identify (1) how many letters addressed "best practices" rather than safety violations and (2) how many other enforcement actions did not involve fines.

OPS has not assessed the effectiveness of its reduced reliance on fines. However, OPS reported in 1997 that some other federal agencies—including the Federal Railroad Administration, the Federal Aviation

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Administration, and the Occupational Safety and Health Administration—share OPS' philosophy concerning the use of fines. For example, the report noted that the Federal Railroad Administration generally gives a rail carrier the opportunity to correct a safety problem before formally citing the carrier for violations and suspends proposed penalties in return for the carrier's agreeing to take immediate corrective action. The report did not assess the extent to which federal agencies that agree with OPS' approach have reduced their reliance on fines.

While some state pipeline regulators share OPS' enforcement approach for the intrastate pipelines under their jurisdiction, others continue to use fines extensively as a deterrent to noncompliance. For example, a Michigan official told us that Michigan pipeline safety regulators typically do not impose fines. In 1998, the state imposed no fines, and in 1999, it imposed only three of about \$1,000 each. According to the Michigan official, Michigan regulators have always believed that civil penalties are not a strong deterrent to noncompliance and the few fines that Michigan does impose are for more serious violations. In contrast, Ohio pipeline safety regulators believe fines are an effective enforcement tool. According to one Ohio pipeline safety official, over the past 7-8 years, Ohio has imposed an average of one fine per year for approximately \$50,000. In Ohio, the amount of the civil penalty depends on the seriousness of the violation and the size of the operator, and the penalties have ranged from \$300 to \$125,000.

OPS' Responsiveness to the Safety Board's Recommendations and to Statutory Requirements Has Been Mixed

OPS has a mixed record in responding to the Safety Board's recommendations. Historically, it has had the lowest rate of any transportation agency for implementing these recommendations. Some of the recommendations that OPS has not fully implemented have dealt with issues that the Safety Board has repeatedly reported on, such as the use of safety valves to rapidly shut down pipelines after ruptures and periodic internal inspections of pipelines to identify defects. OPS has recently taken action to improve its responsiveness in several other areas that the Safety Board has addressed, including excavation damage, corrosion control, and data quality. While Safety Board officials are encouraged by these recent efforts, they remain somewhat skeptical of OPS because, in the Safety Board's opinion, OPS has not followed through on past promises to implement the Safety Board's recommendations.

Several federal statutes also address pipeline safety issues, including a number of those covered by the Safety Board's recommendations. Specifically, since 1988, the Congress has imposed 49 requirements

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designed to improve pipeline safety. OPS has not implemented 22 of these requirements, 12 of which date from 1992 and prior years.

OPS Has Not Fully Implemented the Safety Board's Recommendations, but May Be Improving Its Responsiveness

Since 1967, the Safety Board has made 243 recommendations to OPS in response to its investigations of significant pipeline accidents (such as those in which a fatality has occurred). According to the Safety Board, OPS implemented only 69 percent of these recommendations and has historically had the lowest response rate of any transportation agency. (See table 3.) However, because this measure includes data from over 30 years, it may not accurately reflect OPS' current efforts to implement the Safety Board's recommendations.¹⁸

¹⁸According to Safety Board officials, a measure to capture an agency's recent (e.g., within the last 5 years) efforts would not be meaningful because (1) many of the agency's actions in response to the recommendations would probably not be complete and (2) the agency might not follow through on promises to implement recommendations.

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Table 3: Transportation Agencies' Implementation Rates for Safety Board Recommendations, 1967-99

Transportation agency	Total number of recommendations	Implementation rate (percent)
Maritime Administration	17	100
Secretary of the Department of Transportation	247	88
Federal Highway Administration	446	87
National Highway Traffic Safety Administration	278	87
Federal Aviation Administration	3,756	83
Federal Transit Administration	66	82
United States Coast Guard	1,162	74
Federal Railroad Administration	483	73
Research and Special Programs Administration	374	72
Office of Pipeline Safety (within the Research and Special Programs Administration)	243	69
Total/average rate	6,829	81

Note: The Research and Special Programs Administration also includes the Office of Hazardous Materials Safety, which has received 131 recommendations and whose implementation rate was 75 percent from 1967 through 1999.

Source: National Transportation Safety Board.

Many of the Safety Board's recommendations deal with recurring issues, such as the use of valves to rapidly shut down pipelines after a rupture, the need for periodic internal inspections of pipelines, and the need to ensure that pipeline operators are adequately trained to respond to emergencies. According to OPS officials, OPS rarely disagrees with the Safety Board on the issues covered in the recommendations. However, strong differences exist between the agencies on whether and how to implement the recommendations, as the following examples show:

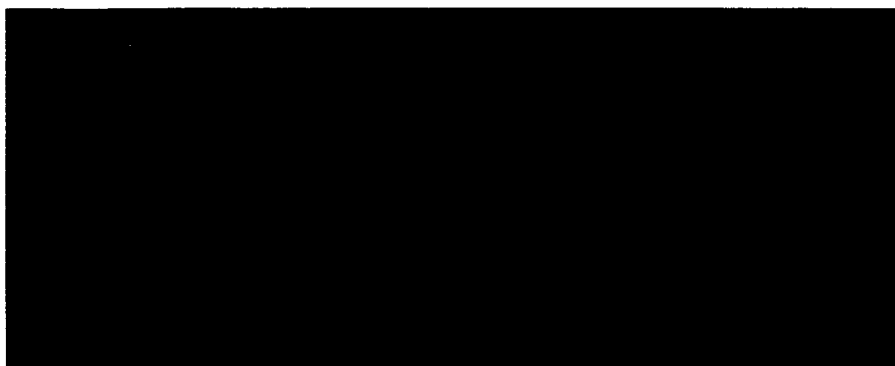
- The Safety Board has issued 11 recommendations since 1971 on using valves to rapidly shut down the flow of product to a ruptured pipeline to mitigate damage. The Safety Board has recommended that OPS require the use of excess flow valves—valves that stop the flow of gas on smaller service lines, such as natural gas distribution lines, when the flow exceeds a specified amount—on all new single-family residential high-pressure service lines. In addition, the Safety Board continues to

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- OPS has several initiatives under way to improve the quality of the accident data reported by pipeline operators. OPS is conducting a pilot project with the American Petroleum Institute to encourage oil pipeline operators to voluntarily report more detailed information than OPS normally collects on accidents. For example, the pilot uses 20, rather than 5, categories of accident causes and lowers the threshold of accidents to be reported from 50 barrels of product spilled to 5 gallons spilled. Data from this pilot, which should begin to be available in the spring of 2000, may be better for analyzing trends in areas such as causes, property damage, and remediation costs. OPS has also drafted a new accident-reporting form for liquid pipeline accidents that incorporates the expanded categories of accident causes that are being used in the pilot, and it plans to modify the forms for natural gas transmission and natural gas distribution pipeline accidents. Finally, in a recent report, the Department of Transportation's Inspector General recommended that OPS collect more complete, detailed information on the causes of accidents, and OPS agreed to do so.¹⁹

OPS and Safety Board officials have been meeting biannually to discuss outstanding recommendations and work to resolve disagreements between the agencies. Safety Board officials have been pleased with many of OPS' actions and the improved communications between the agencies during the last year. However, many of the actions are incomplete, and some, such as OPS' proposed rule requiring the enhanced protection of high-consequence areas, will not fully address the recurring pipeline safety issues that have prompted the Safety Board's recommendations. Therefore, Safety Board officials are waiting to see the results of OPS' promised actions before assessing the extent to which OPS' responsiveness has improved.

OPS Has Not Fully Implemented Statutory Requirements

In addition to the Safety Board's recommendations, 49 congressional requirements have been imposed since 1988 to improve the safety of pipelines and enhance OPS' ability to oversee the pipeline industry.²⁰ (App. IV lists these pipeline safety statutory requirements and their status.) Twenty-two of these requirements have not been implemented, and 12 of

¹⁹*Pipeline Safety Program*, Office of Inspector General, U.S. Department of Transportation, RT-2000-069 (Mar. 13, 2000).

²⁰The Senate and House Appropriations Committees have also directed OPS to carry out various activities in reports accompanying OPS' annual appropriations. Several of these directives reiterate the statutory requirements.

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them date from 1988 to 1992. (See table 4.) Ten of these 12 requirements were to be completed by deadlines stated in the statutes and are now between about 5 and 11 years past these deadlines.

Table 4: Status of Implementation of Statutory Requirements, 1988-2000

Legislation	Total number of requirements	Number of requirements not complete
Pipeline Safety Reauthorization Act of 1988	11	3
Oil Pollution Act of 1990	1	0
Offshore Pipeline Navigational Hazards (1990)	6	1
Pipeline Safety Act of 1992	15	8
Accountable Pipeline Safety and Partnership Act of 1996	15	10
Transportation Equity Act for the 21st Century (1998)	1	0
Total	49	22

Source: GAO's analysis of pipeline safety legislation from 1988-2000.

The statutory requirements often addressed the same issues as the Safety Board's recommendations. For example, three requirements from 1988, 1992, and 1996 called for periodic inspections of pipelines, five requirements from 1988, 1992, and 1996 addressed the use of safety valves, and four requirements from 1988, 1992, 1996, and 1998 addressed excavation damage. These requirements also cover other issues. For example, in October 1992, the Congress required OPS to define by October 1994 areas unusually sensitive to environmental damage from a hazardous liquid pipeline rupture. According to OPS officials, the agency did not meet the statutory deadline because reaching a consensus with other federal agencies and environmental groups on a definition of these areas has been complicated by the broad range of definitions currently in use. OPS issued a proposed rule on a definition of areas unusually sensitive to environmental damage on December 30, 1999, and expects to complete the final rule by the end of 2000.

Both OPS and the Safety Board agree that there is a need to increase pipeline safety in the areas where the Safety Board has made recommendations—areas that are also frequently addressed by statutory requirements. The agencies' disagreement over several of the Safety Board's recommendations focus on how best to achieve that result. Although some disagreements remain, the Safety Board has been

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encouraged by OPS' recent actions to implement its recommendations and the statutory requirements. We believe that it is essential for OPS and the Safety Board to continue to work together to resolve their differences.

Conclusions

We are concerned that OPS is discontinuing the use of states to help conduct inspections of interstate pipelines primarily because of logistical difficulties in scheduling systemwide inspections when states are involved. States' familiarity with pipelines in their jurisdictions could aid in identifying the very risks that OPS is hoping to mitigate through its planned risk management approach to safety regulation. This familiarity could argue for states' participation in reviewing integrity management programs that pipeline companies would be expected to develop under a risk management approach. In addition, a combined federal and state approach to overseeing pipeline safety could better leverage federal resources.²

OPS' approach of working constructively with pipeline companies and reducing its reliance on monetary penalties to enforce its regulations is consistent with the actions of several other federal regulators, such as the Federal Railroad Administration, as well as several state pipeline regulators. However, a reduction in enforcement actions that result in fines from nearly 50 percent to 4 percent represents a significant change in how OPS obtains compliance with pipeline safety regulations. If pipeline companies are achieving compliance through less punitive actions, then OPS' reduced reliance on fines may be reasonable. However, OPS has not assessed whether (1) less punitive actions are effective in achieving the desired results or (2) its actions to reduce reliance on fines go farther than other agencies' actions. An assessment of the degree to which OPS' change in approach to enforcement actions has maintained, improved, or lessened compliance with safety regulations could provide a basis to judge whether the agency is moving in the right direction.

Recommendations

We recommend that the Secretary of Transportation direct OPS to work with state pipeline safety officials to determine which federal pipeline safety activities would benefit from state participation and, for those states willing to participate, integrate state participation into these activities.

We further recommend that, if OPS issues a final rule requiring individual pipeline companies to develop integrity management programs, the Secretary should direct OPS to allow state inspectors to help review the

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programs developed by the companies that operate in their states to ensure that these companies have identified and adequately addressed safety risks to their systems.

Finally, we recommend that the Secretary of Transportation determine whether OPS' reduced use of fines has maintained, improved, or decreased compliance with pipeline safety regulations.

Agency Comments and Our Evaluation

We provided a draft of this report to DOT for its review and comment. We met with officials from DOT, including OPS' Director, Office of Policy, Regulations, and Training, to obtain their comments. The DOT officials generally agreed with the draft report's recommendations. The officials stated that ongoing regulatory and legislative activities demonstrate that efforts are under way to implement the draft report's recommendation that OPS work closely with the states and their pipeline inspectors to further improve the level of pipeline safety. For example, DOT's proposed legislation to reauthorize the pipeline safety program would include specific authority for states to participate in new construction inspections and accident investigations on interstate pipelines. The officials told us that DOT's initiatives are intended to enable state inspectors to better focus their oversight efforts and to improve OPS' interactions with the states. The officials also told us that DOT is moving to substantially increase the funding available for state inspection activities and, for the first time, provide funding for certain state inspection activities on interstate pipelines. We are pleased that DOT recognizes the importance of working cooperatively with the states in overseeing pipeline safety. However, we continue to believe that, in addition to new pipeline construction and accident investigations, DOT should specifically allow the states to participate in reviews of interstate pipeline companies' integrity management programs, as we recommended in the draft report.

According to the officials, while OPS increasingly favors the use of corrective action and other compliance orders, it maintains all traditional enforcement tools and applies them when necessary. Furthermore, the officials told us that DOT's proposal to reauthorize the pipeline safety program is intended to strengthen the enforcement tools available to OPS. The officials maintain that the new enforcement approach has obtained more immediate and thorough corrective and remedial actions than would have been obtained through an approach based solely on increased fines. We recognize that DOT's pipeline safety program reauthorization proposal is intended to strengthen the enforcement tools available to OPS. However,

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while DOT officials claim that OPS' new approach of using corrective action and other compliance orders in lieu of fines has achieved benefits that would not have been obtained otherwise, a formal assessment of this new approach, as we recommended in the draft report, is needed to determine whether it is providing an equal, greater, or lesser level of compliance with the regulations.

Finally, the officials emphasized that DOT will continue to require full regulatory compliance even as it moves to further refine its focus on risk. Under OPS' integrity management program for the enhanced protection of pipelines in high-consequence areas, DOT plans to supplement regulatory compliance with a comprehensive examination of individual pipeline systems to identify and act on potential risk factors. DOT told us that this approach will make use of expertise from all aspects of pipeline design, construction, and operation to integrate information in a supplemental evaluation of systemwide risk factors. Once the risks are identified, operators will be required to act on the assessment through repair, prevention, and mitigation. We modified our draft report to further clarify that OPS' proposed integrity management program for the enhanced protection of pipelines in high-consequence areas is intended to be a supplement to, rather than a replacement of, the existing pipeline safety regulations.

DOT officials also provided technical clarifications, which were incorporated as appropriate.

Scope and Methodology

To determine the extent of pipeline accidents from 1989 through 1998 (the most recent year for which data were available), we collected and analyzed OPS' data on pipeline accidents. We did not independently verify the reliability of the data. To ensure an objective comparison across all types of pipelines, we included in our analysis only those accidents that met the reporting criteria common to all types of pipelines—accidents that resulted in a fatality, an injury requiring hospitalization, or \$50,000 or more in property damage. We defined these accidents as "major accidents." We also reviewed more extensive data on the causes of accidents compiled by the Association of Oil Pipe Lines, the American Petroleum Institute, and the American Gas Association.

To determine OPS' implementation of the risk management demonstration program, we reviewed the statutory requirements for the program and program documents maintained on OPS' web-based document

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management system, including program guidance and project applications. We also interviewed OPS officials and representatives from the pipeline companies participating in the program.

To describe OPS' inspection and enforcement efforts since the 1996 act, we reviewed data on OPS' inspections and enforcement actions from 1990 through 1998 and analyzed trends in these activities. We interviewed OPS officials and representatives from the pipeline industry and environmental groups. We conducted telephone interviews with state pipeline safety officials in 12 states that have acted as interstate agents within the last 5 years—Arizona, California, Connecticut, Iowa, Michigan, Minnesota, Nevada, Ohio, New York, Rhode Island, Utah, and West Virginia. We also visited three states—Texas, Virginia, and Washington—where major pipeline accidents were investigated by the Safety Board and officials have sought a greater role for states in pipeline safety.

To determine OPS' responsiveness to the National Transportation Safety Board's recommendations and statutory requirements, we reviewed the Safety Board's reports and recommendations since 1989, analyzed statistics on the recommendations since 1967, and discussed the results of our analysis with Safety Board and OPS officials. We did not assess the merits of the Safety Board's recommendations or the adequacy of OPS' response. We reviewed pipeline safety statutes, annual appropriations acts, related congressional committee reports, and reports by OPS to identify statutory requirements since 1988. We reviewed OPS' reports and analyses of the status of the requirements. We did not assess the adequacy of OPS' response to statutory requirements or independently verify the status of the requirements.

To determine the status of the ongoing investigation of the accident in Bellingham, Washington, we interviewed representatives and reviewed documents from the following agencies and groups: the National Transportation Safety Board, OPS' Western Region, the Washington Utilities and Transportation Commission, the Washington State Governor's Fuel Accident Prevention and Response Team, the city of Bellingham, SAFE Bellingham, and Olympic Pipe Line Company.

We conducted our work from August 1999 through April 2000 in accordance with generally accepted government auditing standards.

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As arranged with your office, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days after the date of this letter. At that time, we will send copies of the report to congressional committees and subcommittees responsible for transportation safety issues; the Honorable Rodney E. Slater, Secretary of Transportation; the Honorable Kelley S. Coyner, Administrator, Research and Special Programs Administration; the Honorable Jim Hall, Chairman, National Transportation Safety Board; the Honorable Jacob Lew, Director, Office of Management and Budget; and other interested parties. We will make copies available to others upon request.

If you or your staff have any questions about this report, please contact me at (202) 512-3650. Key contributors to this report are listed in appendix V.

Sincerely yours,

A handwritten signature in black ink, reading "Phyllis F. Scheinberg". The signature is written in a cursive style with a large, stylized "P" and "S".

Phyllis F. Scheinberg
Associate Director, Transportation Issues

Appendix I

The Bellingham, Washington, Pipeline Accident

The Olympic Pipe Line Company operates a pipeline system consisting of about 400 miles of pipelines that transport petroleum products from refineries at Cherry Point, Ferndale, and Anacortes in northwestern Washington to Portland, Oregon, and intermediate delivery points. Products transported include gasoline, distillates (heating oil and diesel fuel), and jet fuel. The system is operated by remote control from an operations center located in Renton, Washington.

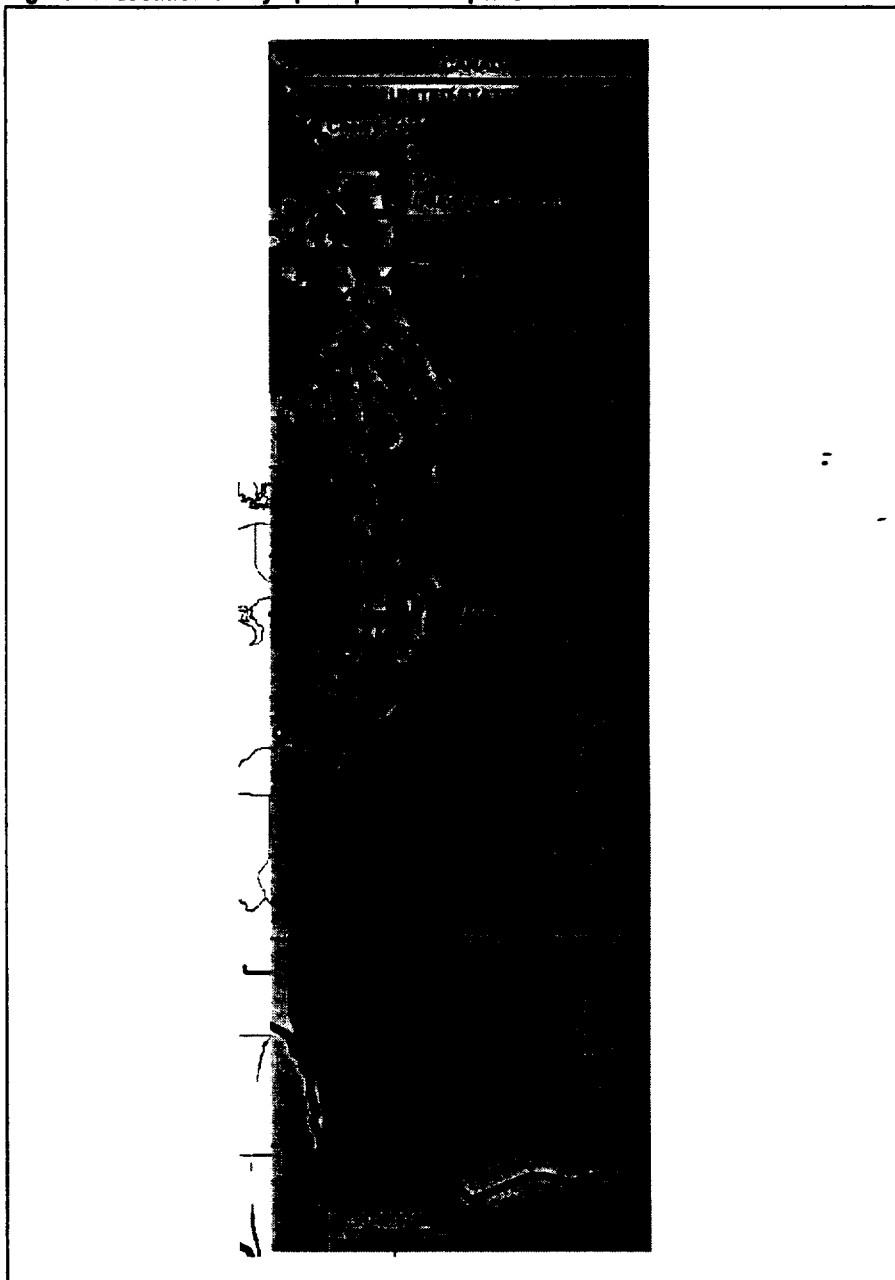
On June 10, 1999, one of Olympic's pipelines transporting gasoline ruptured in the Whatcom Falls Park area of Bellingham, Washington. About 250,000 gallons of gasoline from the pipeline entered the Hannah Creek and Whatcom Creek where the fuel was ignited, resulting in three fatalities and eight injuries. In addition, the banks of the creek were destroyed over a 1.5-mile section, and several buildings adjacent to the creek were severely damaged.

Pipeline Rupture on June 10, 1999

Although the investigation of the accident is ongoing, the National Transportation Safety Board (the Safety Board) and the Department of Transportation's Office of Pipeline Safety (OPS) have preliminarily reconstructed the events leading up to the pipeline rupture. Shortly before the rupture occurred, pipeline operators attempted to start a pump at the Woodinville pumping station to facilitate the smooth flow of gasoline through the pipeline. (See fig. 7.) The pump did not engage, and pressure started to build within the pipeline. A relief valve at the Bayview station was designed to divert the gasoline from the pipeline to a tank to relieve the increasing pressure, and a block valve, also located at the Bayview station, was designed to close and stop the flow of gasoline. The Safety Board believes that the block valve closed as it should have done. However, gasoline continued to be pumped into the pipeline at Cherry Point, causing the pressure in the pipeline segment between Cherry Point and Bayview to continue increasing. The pipeline subsequently ruptured about midway along the segment at the Bellingham water treatment plant, near Whatcom Creek.

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Figure 7: Location of Olympic Pipe Line Rupture



Source: National Transportation Safety Board.

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According to the Chairman of the Safety Board, preliminary data show that when the rupture occurred, the pressure in the pipeline was well above normal operating levels. However, the pressure was substantially below the maximum pressure that a pipe of this design and size should have been able to withstand, and it was below the maximum allowable surge pressure permitted by regulatory standards.

According to Safety Board officials, the pipeline shut down after the rupture. However, Olympic Pipe Line controllers restarted the pipeline about 45 minutes later, and gasoline was pumped into the damaged segment for about 17 minutes. Between 250,000 and 300,000 gallons of gasoline (from the initial rupture and the subsequent restart of the pipeline) flowed from the damaged pipeline to the Hannah Creek and Whatcom Creek. Whatcom Creek—a salmon habitat—flows through Whatcom Falls Park in Bellingham.

The Safety Board's
Investigation of the
Accident

Investigators from the Safety Board are examining several factors that may have caused or contributed to the accident, including excavation damage, valve malfunctioning, operator training, and computer issues. However, several key activities in the Safety Board's investigation have been suspended because (1) Olympic Pipe Line Company employees with direct knowledge of the events have exercised their Fifth Amendment rights and have not responded to the Safety Board's questioning and (2) the Department of Justice halted destructive testing of the pipeline segment in order to preserve evidence. On April 5, 2000, the Safety Board was authorized to proceed with the testing of the pipeline segment.

The Safety Board's preliminary visual inspection of the ruptured pipeline segment indicated external damage to the pipeline at the point of rupture and additional damage to the area. In 1993 and 1994, a contractor working on behalf of the city of Bellingham installed new water lines across Olympic's pipeline at points approximately 20 feet and 10 feet south of the rupture. In 1991, an internal inspection of the pipeline did not identify any anomalies in the immediate vicinity of the rupture. However, two internal inspections conducted in 1996 and 1997 after the construction of the water lines identified several anomalies in the vicinity of the rupture. According to the Chairman of the Safety Board, Olympic Pipe Line indicated that the anomalies did not meet the applicable criteria for excavating the pipeline for a closer examination. The Safety Board is determining what criteria were used and plans to meticulously test the ruptured pipeline segment to determine whether external damage may have contributed to the rupture.

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The Safety Board is also investigating the performance of the relief valve and the block valve at the Bayview station. Because Olympic modified the relief valve when it was installed, the Safety Board is examining whether the company followed the manufacturer's specifications for the modification. In addition, preliminary information indicates that the block valve had closed over 50 times in the 6 months prior to the accident, often because of pressure buildups similar to the one that occurred before the accident on June 10. The Safety Board is evaluating these events to determine the pressures involved, the functioning of the relief valve, and the possible impact of the pressure buildups on the overall integrity of the pipeline segment that ruptured.

The Chairman of the Safety Board also stated that the Safety Board wants to document and analyze the data available to controllers at the time of the accident. According to the Chairman, the controllers seem to have been unaware of the rupture for an extended period of time and the fact that they restarted the pipeline after the rupture suggests a significant performance failure. The Chairman noted that the Safety Board does not know whether this can be traced to insufficient training, inadequate qualifications, equipment malfunctions, poor design in the computer-based control system, or some other undetermined factor.

Finally, Olympic initially reported that the computer system that controls the pipeline experienced a "slowdown" during the accident that affected the ability of the controllers to observe the pipeline's functions and to change settings. The Safety Board's preliminary analysis of the computer tapes did not identify a slowdown. Olympic has reported that such a slowdown cannot be verified or reproduced.

**OPS' Actions
Following the Accident**

On June 18, 1999, OPS issued a corrective action order to Olympic Pipe Line Company (owned and operated by Equilon Pipeline Company, LLC) which directed Olympic not to operate the damaged pipeline segment until the company, among other things, reviewed its computer system to determine the cause of the slowdown and take corrective action, tested mainline valves, and submitted a plan to OPS addressing factors that contributed to the rupture. The order also restricted the operating pressure on the remainder of the pipeline until OPS approves a return to normal operating pressure. The order was amended on August 10, 1999, and again on September 24, 1999, to address safety issues identified during the ongoing investigation. For example, the subsequent orders required Olympic to further reduce the pressure on certain pipeline segments,

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develop and implement a training program for controllers on the use of the computer system (including abnormal operations), and conduct hydrostatic tests of certain segments of the pipeline (draining the pipeline, filling it with water, and increasing the pressure within the pipeline to identify weak points). In addition to the corrective action order, OPS issued an advisory to all pipeline operators to check the adequacy of the computer resources devoted to monitoring and controlling their pipeline operations.

OPS inspectors have been monitoring Olympic's corrective actions. The inspectors are (1) working as a party to the Safety Board's investigation, (2) conducting an enforcement investigation, and (3) monitoring upgrades and repairs to the pipeline in accordance with the corrective action order. OPS also retained an independent expert to evaluate complex data from the internal inspections conducted in 1996 and 1997. In addition, OPS stationed a pipeline inspector in Washington State. This inspector will oversee the safety and environmental integrity of pipelines in the upper Northwest region and work on issues related to the Bellingham accident.

On January 18, 2000, Olympic asked OPS for permission to restart the pipeline. As of April 2000, OPS officials had sent a response to Olympic detailing areas where it needed to take additional actions before the pipeline could be returned to limited service. When OPS decides to allow Olympic to restart the pipeline, the pipeline will be brought back into service in incremental steps.

Actions Taken by the
City of Bellingham and
Its Citizens

Within a week after the accident, officials from the city of Bellingham realized that the agreement under which Olympic operated its pipeline within the city limits had expired. According to city officials, the need for Olympic to re-obtain the city's permission to operate its pipeline gave them some added leverage in negotiating several agreements with Olympic. The city extended the expired agreement until May 4, 2000, provided that Olympic complied with two other agreements between the city and Olympic—a safety action plan and a master agreement.

The safety action plan includes safety-related activities to be performed by Olympic before the section of the pipeline that ruptured can be restarted at reduced pressure, as well as activities to be performed at various stages after restarting the pipeline. These activities include (1) the testing of existing valves and installation of new valves; (2) hydrostatic testing of the pipeline; (3) computer testing and modifications; (4) the installation of an additional leak detection system; (5) an internal inspection of the pipe

Appendix I
The Bellingham, Washington, Pipeline
Accident

within 3 months of startup (and in any event no later than 6 months after startup); (6) field inspections and repairs based on the results of the internal inspection, and (7) a management audit to be performed by an independent party. OPS incorporated participation in the management audit into the September 24, 1999, amendment to its corrective action order.

On February 11, 2000, Olympic sent a letter to the city of Bellingham responding to the conditions for restarting the pipeline. The city continues to have concerns about Olympic's response.

The master agreement specifies that Olympic cannot restart the pipeline until it has satisfied the requirements in the city's safety action plan and OPS' corrective action order. In addition, the master agreement requires Olympic to study the feasibility of rerouting the pipeline around Bellingham. On February 1, 2000, Olympic submitted a report to the city in which it concluded that rerouting the pipeline was not feasible because it was unlikely that a new route would gain permitting approval from state and federal agencies. As of April 2000, the city had not responded to the report's conclusions.

One week after the accident, a group of citizens from Bellingham formed a group—SAFE Bellingham—to ensure that the creek would be restored, that Olympic would be held accountable, and that actions would be taken to mitigate future accidents. SAFE Bellingham has organized a coalition of communities that have experienced pipeline accidents to promote changes to federal pipeline safety regulations and has drafted a proposal for a local advisory committee to monitor pipeline safety within states.

Actions Taken by the
State of Washington

The governor of Washington established a task team after the accident to evaluate pipeline safety within the state. The task team issued a report in December 1999 that recommends changes in law and practice at the federal, state, and local levels and changes in practice by fuel transmission pipeline operators in Washington. For example, the report recommends that the state pursue (1) federal regulation that would allow states to regulate the portions of interstate pipelines within their borders using standards more stringent than OPS', (2) federal legislation that would authorize states to receive higher levels of grant support from OPS, and (3) state executive branch and legislative changes that would strengthen pipeline safety.

Appendix I
The Bellingham, Washington, Pipeline
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As of April 2000, the state was working on an agreement with OPS regarding the inspection of interstate pipelines. On March 28, 2000, the governor signed a bill that establishes a statewide program to improve pipeline safety in Washington by having, among other things, the state's Utilities and Transportation Commission adopt new regulations and provide technical assistance to local governments. The bill also establishes a citizen advisory committee to help the public, local governments, and the industry work with the state on pipeline safety. Finally, the bill increases the penalties for failing to call a central number to identify the location of pipelines before digging.

Actions Taken by
Olympic Pipe Line
Company

In addition to responding to OPS' corrective action order and the city of Bellingham's safety action plan, Olympic issued a corridor safety action plan in October 1999 that applied many of the same actions being taken in the Bellingham area to the entire pipeline corridor from Ferndale to Portland. For example, Olympic's action plan includes requirements for valve testing and internal inspections along the entire pipeline.

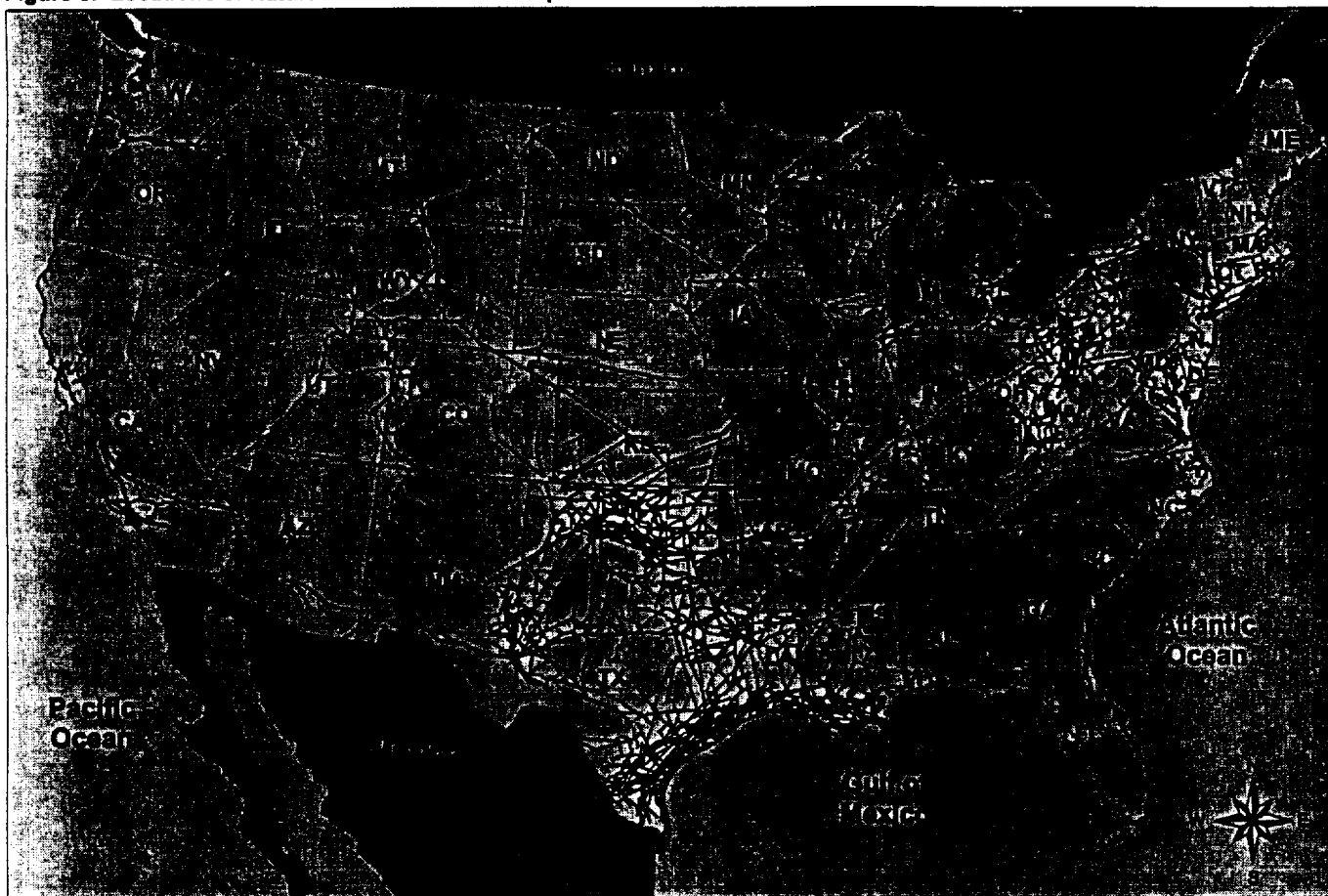
Representatives from Olympic are on a committee with representatives from the city of Bellingham and other consultants to restore and improve Hannah and Whatcom creeks. Olympic has provided the initial funding for restoration and improvement efforts, which include erosion control, replanting, and building new salmon spawning pools. According to a member of the committee, Whatcom Creek's water quality has been restored and several species of salmon have been observed in the creek.

Barge and truck transport are being used to deliver petroleum products during the shutdown of the damaged pipeline segment. According to attorneys representing Olympic, maintaining delivery has been difficult at times, especially since Olympic is the sole supplier of jet fuel to the Seattle-Tacoma Airport.

Appendix II

Maps of Natural Gas Transmission and Hazardous Liquid Pipelines

Figure 8: Locations of Natural Gas Transmission Pipelines



Source: OPS, based on data from MAPSearch Services.

**Appendix II
Maps of Natural Gas Transmission and
Hazardous Liquid Pipelines**

Figure 9: Locations of Hazardous Liquid Pipelines



Source: OPS, based on data from MAPSearch Services.

Appendix III

Status of Risk Management Demonstration Projects

Since the inception of the risk management demonstration program, OPS has approved six pipeline companies' risk management projects for the program. These individual projects are designed to demonstrate the benefits of risk management under a variety of conditions, including differences in products, the ages of pipeline systems, environments, geography, and operating conditions (see table 5).

Table 5: Projects Approved for the Risk Management Demonstration Program

Operator	Regions affected	Project focus	Date approved
Equilon Pipeline	Southwest	Equilon is including two separate interstate pipeline systems in its project: a 205-mile segment of an ethylene pipeline and a 260-mile segment of a carbon dioxide pipeline. For these pipeline segments, Equilon is developing a comprehensive risk management program for assessing all hazards and risks associated with the operation of these pipelines. A major focus of the project is damage prevention during excavation and construction.	March 1998
Exxon Mobil	Central	Exxon Mobil is demonstrating its release prevention (tank integrity) program at its crude oil breakout facility in Patoka, Illinois. The project will examine how Exxon Mobil's release prevention measures will work in conjunction with OPS' proposed standards for aboveground storage tanks.	August 1998
Phillips Pipe Line Company	Southwest	Phillips is using risk management along a 60-mile segment of both an 18-inch and a 12-inch refined oil products pipeline. The project will explore ways of minimizing the risks associated with excavation work along the pipelines to reduce or eliminate damage from outside forces.	August 1998
Kinder Morgan, Inc.	Central, Southwest	The company is incorporating risk management into a 13,000-mile natural gas pipeline system. It hopes to form a comprehensive risk management program based on existing company programs such as pipeline integrity, regulatory compliance management, and emergency response.	December 1998
Chevron Pipe Line	Western	Chevron is including a 330-mile portion of its Salt Lake Products Pipeline System in the program. The system consists of two 8-inch product pipelines, one transporting gasoline and the other distillates such as diesel and jet fuel. Among other tasks, Chevron will conduct internal pipeline inspections and geologic hazard assessments of the pipelines for its project.	February 1999
Northwest Pipeline	Western	Northwest is developing a risk management program for its entire 3,900-mile natural gas system. The project will explore means of assessing and addressing risks presented by a pipeline in rugged terrain susceptible to land movement and investigate the risk-reduction benefits of certain new technologies.	January 2000

Source: GAO's analysis of information from OPS.

The direct federal costs of the risk management demonstration program are expected to be nearly \$8 million from fiscal year 1996 through fiscal year 2000. According to OPS officials, OPS has not funded the participant companies' costs for the risk management demonstration projects but has

**Appendix III
Status of Risk Management Demonstration
Projects**

incurred direct support costs for personnel, travel, and contractor support for evaluating and auditing the demonstration projects. In addition, OPS has provided grants to states totaling about \$340,000 for travel costs associated with the projects. These direct support costs decreased from a total of about \$1.8 million in fiscal year 1996 (the first year of the program) to about \$1.4 million in fiscal year 1999, but they are expected to increase to about \$1.6 million in fiscal year 2000, primarily because of increases in contractor support costs. (See table 6.)

Table 6: Federal Cost of the Risk Management Demonstration Program, by Fiscal Year

Description	Fiscal year					Total
	1996	1997	1998	1999	2000	
Federal salary and benefits ^a	\$355,000	\$363,000	\$379,000	\$393,000	\$425,000	\$1,915,000
Estimated travel costs	200,000	200,000	200,000	200,000	200,000	1,000,000
Contractor support costs	1,249,956	1,069,053	811,599	708,346	900,000 ^b	4,738,954
State grants	0	40,000	100,000	100,000	100,000	340,000
Total	\$1,804,956	\$1,672,053	\$1,490,599	\$1,401,346	\$1,625,000	\$7,993,954

^aEstimated salary and benefits for five full-time equivalent employees per year.

^bAccording to OPS officials, this is an amount obligated for the 15-month period from Oct. 1, 1999, through Dec. 31, 2000.

Source: GAO's analysis of OPS' documents.

Appendix IV

OPS' Action on Statutory Requirements, 1988-2000

This appendix consists of tables that summarize (1) the requirements for OPS established in six statutes and (2) the actions OPS has taken since 1988 in response to these requirements.

Table 7: Pipeline Safety Reauthorization Act of 1988 (P.L. 100-561, Oct. 31, 1988)

Section	Statutory requirement	Status
102 (gas) 202 (liquid)	<u>Reporting standards:</u> Within 1 year, establish standards for operators to provide information, including the following: Name, address, phone number; Map; Pipeline characteristics; Description of products transported; Operations manual; Emergency response plan.	<u>Closed:</u> 49 C.F.R. 192 and 195 require gas and hazardous liquid pipeline operators to (1) maintain records of the characteristics and maintenance history of their pipelines and (2) prepare an operations manual and an emergency manual. In addition, OPS, in conjunction with the National Pipeline Mapping System, has developed and published standards for collecting information on pipelines and their environment. OPS and the states are now receiving data from the pipeline companies. In addition, OPS is working with the hazardous liquid pipeline industry to develop a voluntary annual report that contains more information than is currently required, by regulation, from natural gas pipeline companies. This information will be provided to OPS by the end of 2000 through a voluntary data initiative of the American Petroleum Institute. The information anticipated from this ongoing initiative will likely make it unnecessary to require an annual report from hazardous liquid pipeline companies.
102 (gas) 202 (liquid)	<u>Pipeline inventory:</u> Establish standards to require operators, within 1 year, to complete and maintain an inventory of all types of pipe used, including the materials used and a history of any leaks.	<u>Open:</u> OPS formed a data team with the hazardous liquid pipeline industry to provide for the voluntary submission of data on pipeline facilities. During 1999, the hazardous liquid pipeline industry pilot-tested a system to assess the effects of the team's data collection recommendations; an analysis of the results will soon be completed. Pipe inventory standards for voluntary reporting are subject to further development. In 2000, OPS revised its annual report forms for gas and hazardous liquid transmission pipeline companies to provide better inventory information.
105(2) (gas) 209 (liquid)	<u>Accident coordination:</u> Within 1 year, establish procedures to more effectively coordinate the response of federal agencies and the states to pipeline accidents.	<u>Closed:</u> OPS coordinates accident response procedures with the National Transportation Safety Board, the Environmental Protection Agency, the Occupational Safety and Health Administration, the Coast Guard, the Federal Railroad Administration, and the Minerals Management Service through memorandums of understanding, letters of agreement, and informal undertakings. Parts 192 and 195 both require pipeline companies to provide information to local emergency response organizations to improve coordination during accidents. Liquid pipeline companies coordinate with federal response agencies and state and local agencies in planning for pipeline spills under the Oil Pollution Act. OPS participates in emergency response exercise programs.

Continued

**Appendix IV
OPS' Action on Statutory Requirements,
1988-2000**

Section	Statutory requirement	Status
108(a)(2) (gas) 207(a) (liquid)	<u>Inspection frequency</u> : Inspect and, as appropriate, require the testing of pipeline facilities at specified intervals, but no less frequently than once every 2 years; master meter operators can be inspected less frequently; the frequency and type of inspections shall be determined on a case-by-case basis, considering factors such as location, characteristics, and materials transported.	<u>Closed</u> : The Accountable Pipeline Safety and Partnership Act of 1996 (49 U.S.C. 60108(b)) eliminated the requirement for testing at 2-year intervals.
108(b) (gas) 207(b) (liquid)	<u>Smart pig accommodation</u> : Establish standards requiring that new and replacement pipe shall accommodate the passage of smart pigs.	<u>Open for certain gas pipelines</u> : A final rule for all pipelines was published (59 F. R. 17275, 4/12/94). Notice 2 (59 F.R. 49896, 9/30/94) extended the compliance date for existing gas transmission lines and modified the requirement for offshore and rural gas transmission lines. Notice 3 (60 F.R. 7133, 2/7/95) suspended enforcement of the final rule's requirements for modifications to sections of onshore gas transmission lines and for new and existing offshore gas transmission lines. A final rule in response to petitions for reconsideration is being prepared for publication in 5/00.
108(c)(gas)	<u>Master meter study</u> : Assess the need for an improved inspection program for master meter systems and issue a report within 18 months.	<u>Open</u> : A final report, <i>An Analysis of Natural Gas Master Meter Systems (Definition and Program) from a Federal Perspective</i> , - was issued 8/15/79. An additional study on master meter systems was drafted following a survey of the states. The data on master meter systems included in the report are being updated. The report will be finalized and issued by the end of 2000.
211(a) (liquid)	<u>Carbon dioxide</u> : Regulate carbon dioxide transported by pipeline and amend regulations as appropriate to ensure the safe transportation of carbon dioxide by pipeline.	<u>Closed</u> : 49 C.F.R. part 195 was amended for carbon dioxide on 6/21/91.
303(a)	<u>One-call systems</u> : Within 18 months, issue regulations establishing minimum federal requirements for establishing and operating one-call notification systems for adoption by states.	<u>Closed</u> : 49 C.F.R. 198, Subpart C, 9/20/90 addresses one-call notification; also, 49 C.F.R. 192.614 and 49 C.F.R. 195.442, 11/19/97, mandate states' participation in one-call systems.
304	<u>Smart pig feasibility study</u> : Assess the feasibility of requiring the inspection of transmission facilities with smart pigs at periodic intervals and issue a report within 18 months.	<u>Closed</u> : OPS issued a report, <i>Instrumented Internal Inspection Devices</i> , in 11/92.
305	<u>Emergency flow valve feasibility study</u> : Study the safety, cost, feasibility, and effectiveness of requiring operators to install emergency flow-restricting devices and issue a report within 1 year.	<u>Closed</u> : A study sponsored by the Research and Special Programs Administration, <i>Emergency Flow Restricting Devices Study</i> , was issued in 3/91.
306	<u>Feasibility of regulating excavation activity</u> : Assess the feasibility of regulating persons whose excavation activities may result in damage to pipeline facilities and issue a report within 1 year.	<u>Closed</u> : A report, <i>Examination of the Feasibility of Regulating Excavators</i> , was issued in 10/90.

Continued from Previous Page

Source: For columns 1 and 2, GAO's analysis of pipeline safety statutes; for column 3, status reports from OPS.

**Appendix IV
OPS' Action on Statutory Requirements,
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Table 8: Oil Pollution Act of 1990 (P.L. 101-380, Aug. 18, 1990)

Section	Statutory requirement	Status
4202(a)(6), (b)(4)	<u>Response plans for onshore oil pipelines:</u> Issue regulations for oil spill response plans for onshore oil pipelines by 8/18/92.	<u>Closed:</u> An interim final rule on onshore facilities was published (58 F.R. 244, 1/5/93). Response plans have been submitted under this interim rule. The final rule, incorporating experience in operating spill response systems and reviewing plans, is to be issued in 5/00.

Source: For columns 1 and 2, GAO's analysis of pipeline safety statutes; for column 3, status reports from OPS.

Table 9: Offshore Pipeline Navigational Hazards (P.L. 101-599, Nov. 16, 1990)

Section	Statutory requirement	Status
1(a) (gas) 1(b) (liquid)	<u>Reporting standards:</u> Within 6 months of 11/16/90, establish standards defining "exposed pipeline facility" and "hazard to navigation."	<u>Closed:</u> 49 C.F.R. 192.3 and 195.2 define these terms.
1(a) (gas) 1(b) (liquid)	<u>Hazardous conditions:</u> Establish, by regulation, a program requiring operators of offshore and navigable water pipelines to report potential or existing navigational hazards involving pipeline facilities to the Secretary through the Coast Guard (as enacted, limited to the Gulf of Mexico and its inlets).	<u>Closed:</u> 49 C.F.R. 191.27, 192.612, 195.57, and 195.413 specify reporting procedures for pipelines in the Gulf of Mexico and its inlets. In addition, OPS issued alert notices to the offshore fishing industry (ALN-90-01) warning of hazards to fishing vessels from exposed pipelines and to Gulf of Mexico operators (ALN-98-03) warning of the possibility of exposed pipelines after Hurricane Georges.
1(a) (gas) 1(b) (liquid)	<u>Permanent inspections:</u> Establish an inspection program for offshore and navigable water pipelines no later than 30 months after 11/16/90 (as enacted, limited to the Gulf of Mexico and its inlets).	<u>Open:</u> OPS signed a memorandum of understanding with the Minerals Management Service to define inspection responsibilities for offshore pipelines. A proposed rule for periodic underwater pipeline inspections is now being prepared for publication by mid-2000.
1(a) (gas) 1(b) (liquid)	<u>Burial:</u> Require, by regulation, that exposed or hazardous pipelines be buried within 6 months after the date that the condition of the pipeline is reported to the Secretary (unless the Secretary extends the time period for compliance).	<u>Closed:</u> 49 C.F.R. 192.612 and 195.413 impose requirements for pipelines in the Gulf of Mexico and its inlets.

Continued

**Appendix IV
OPS' Action on Statutory Requirements,
1988-2000**

Section	Statutory requirement	Status
2	<u>Navigation hazards</u> : Establish a program to encourage fishermen and other vessel operators to report potential or existing navigational hazards involving pipelines to the Secretary through Coast Guard field offices.	<u>Closed</u> : 49 C.F.R. 191.23, 191.25, 192.27, 192.612, 192.615, 195.52-.58 establish procedures for reporting accidents and safety-related conditions for both gas and hazardous liquid pipelines. OPS issued a report, <i>Safety-related Condition Reporting</i> , in 7/88. In addition, OPS issued alert notices to the offshore fishing industry (ALN-90-01) warning of hazards to fishing vessels from exposed pipelines and to Gulf of Mexico operators (ALN-98-03) warning of the possibility of exposed pipelines after Hurricane Georges. Fishermen in the Gulf of Mexico now voluntarily provide reports on fishing net snags (which may or may not be on a pipeline), known as "hang" reports. These reports may result in compensation if the Minerals Management Service determines that a hang is on a pipeline facility. Louisiana also maintains its own Fisherman Gear Fund to compensate fishermen for lost nets and equipment in case of hangs on pipelines or production facilities.
3	<u>Study</u> : Study several issues related to underwater pipelines and report to the Congress on the results of actions no later than 6 months after 11/16/90.	<u>Closed</u> : OPS (1) informed operators and fishermen of the problems posed by exposed underwater pipelines and required the reporting of safety-related conditions, (2) completed its collection of computer-assisted maps of all offshore oil and gas lease blocks, (3) contracted with Texas A&M University for a study, issued in 1/98. The study recommended that OPS (1) establish regulations requiring the inspection of pipelines to determine their depth of burial and any need for reburial, (2) use risk analysis to determine the periodicity of future surveys, and (3) require operators to maintain pipelines 3 feet below the natural bottom and develop a mandatory one-call system for marine pipelines. OPS is drafting a proposed rule that will incorporate these recommendations.

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Source: For columns 1 and 2, GAO's analysis of pipeline safety statutes; for column 3, status reports from OPS.

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OPS' Action on Statutory Requirements,
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Table 10: Pipeline Safety Act of 1992 (P.L. 102-508, Oct. 24, 1992)

Section	Statutory requirement	Status
102(a)(2) (gas) 202(a)(2) (liquid)	<u>High-density population areas (for gas and liquid) and environmentally sensitive areas (for liquid):</u> Within 2 years, issue regulations establishing criteria for the identification of all pipeline facilities that are located in high-density and environmentally sensitive areas.	<u>Open:</u> On 4/24/00, OPS issued a proposed rule requiring additional testing, inspection, and remediation of hazardous liquid pipelines in high-consequence areas. The agency issued, on 12/30/99, a proposed rule defining U.S. areas unusually sensitive to environmental damage (64 F.R. 73464). (Comments are due on 8/27/00). An additional proposed rule for the inspection and testing of gas transmission pipelines in high-consequence areas will be issued in 2000.
103(5) (gas) 203(5) (liquid)	<u>Update inspections/smart pigs:</u> Within 3 years, issue regulations requiring the periodic inspection of pipelines in high-density and environmentally sensitive areas, specifying the circumstances, if any, under which inspections should be conducted using smart pigs; when smart pigs are not required, require an inspection method that is at least as effective in providing for the safety of the pipeline.	<u>Open:</u> A proposed rule to require periodic inspections of hazardous liquid pipelines in high-consequence areas was issued on 4/24/00.
104 (gas)	<u>Excess flow valves:</u> (1) Within 18 months, issue regulations prescribing the circumstances, if any, under which operators must install excess flow valves; (2) within 2 years, issue regulations requiring operators to notify, in writing, customers whose lines do not require but can accommodate excess flow valves that such valves shall be installed at the request of the customer if the customer will pay all costs; (3) if there are no circumstances under which operators must install excess flow valves, issue a report within 30 days of such a determination on the reason for the determination; and (4) within 18 months, develop standards for the performance of excess flow valves used to protect lines in natural gas distribution systems.	<u>Closed:</u> A study found that excess flow valves were not cost-effective, and OPS did not require operators to install excess flow valves. However, 49 C.F.R. 192.383, 2/3/98, addresses requirements for notifying customers of the availability of excess flow valves, and 49 C.F.R. 192.381, 6/20/96, addresses performance standards for the valves.
212 (liquid)	<u>Emergency flow restriction devices:</u> (1) Within 2 years, survey and assess the effectiveness of emergency flow restriction devices (including remotely controlled valves and check valves) and other procedures, systems, and equipment used to detect and locate pipeline ruptures and minimize product releases from pipeline facilities; (2) within 2 years after the survey and assessment, issue regulations prescribing the circumstances under which operators must use emergency flow restriction devices and other procedures, systems, and equipment.	<u>Open:</u> OPS issued a proposed rule to solicit data (59 F.R. 2802, 1/19/94). A study sponsored by the Research and Special Programs Administration on emergency flow restriction devices was issued on 9/29/95. A public workshop was held in 10/95. The American Petroleum Institute's leak detection practices were adopted in 49 C.F.R. part 195 on 7/6/98. A proposed rule to require additional testing, inspection, and remediation of hazardous liquid pipelines in high-consequence areas was to be issued by 3/31/00. The American Petroleum Institute is to develop an industry standard on U.S. areas unusually sensitive to damage from a pipeline spill, which may help define pipeline segments, including those in high-consequence areas, that are candidates for emergency flow restriction devices and other inspection, testing, and integrity assurance approaches.

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**Appendix IV
OPS' Action on Statutory Requirements,
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Section	Statutory requirement	Status
106(1) (gas) 205(1) (liquid)	<u>Operator testing</u> : Require testing and certification that addresses the ability to recognize and appropriately react to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits.	<u>Closed</u> : A final rule, to require all pipeline operations and maintenance workers to be qualified to perform their tasks and to be able to recognize and react to abnormal operating conditions, was published on 8/27/99 (64 F.R. 46853). Operators must have qualification plans prepared by 4/27/01 and all workers must be qualified by 10/28/02.
107 (gas)	<u>Replacement of cast iron pipelines</u> : Publish a notice as to the availability of industry guidelines for the replacement of cast iron pipe and, within 2 years after the guidelines are available, survey operators with cast iron piping systems to determine the extent to which each operator has adopted and followed a plan for the safe management and replacement of cast iron, the elements of the plan, and the progress that has been made.	<u>Closed</u> : OPS issued an alert notice (ALN-91-02) reminding all operators of natural gas distribution systems to have a program to identify and replace cast iron piping systems that may threaten public safety. The agency also informed operators of guidelines and computer programs that were available to help operators determine the serviceability of cast iron pipe and schedule its replacement. Cast iron is used exclusively by gas distribution operators that are regulated under state pipeline safety programs. Therefore, OPS' annual auditing of the state pipeline safety programs ensures that the states are monitoring distribution pipeline operators' plans for inspecting, managing, and replacing cast iron pipe. A survey of cast iron pipe in use by operators was completed in 1992 and is now being revised.
109(b) (gas) 208(b) (liquid)	<u>Gathering lines</u> : Within 2 years, issue a regulation defining a "gathering line" and within 3 years, issue a regulation defining a "regulated gathering line."	<u>Open</u> : A proposed rule defining a gas gathering line is expected by mid-2000.
115 (gas)	<u>Customer-owned service lines</u> : (1) Within 1 year, issue regulations requiring operators that do not maintain customer-owned service lines up to the walls of customers' buildings to advise their customers of the requirements for maintaining those lines; (2) within 18 months, review the Department of Transportation's and states' rules, policies, procedures, and other measures concerning the safety of customer-owned service lines and their effectiveness and survey the owners of customer-owned service lines regarding the operation and maintenance of such lines; (3) within 2 years, issue a report on the results of the review and survey; and (4) within 1 year after transmitting the report, take action to promote the adoption of measures to improve the safety of such service lines.	<u>Closed</u> : 49 C.F.R. 192.16, 8/14/95, imposes requirements for notifying customers. The requirement to take action to promote the adoption of measures to improve the safety of customer-owned service lines was eliminated in the Accountable Pipeline Safety and Partnership Act of 1996 (49 U.S.C. 60113).
108(5) (gas) 207(5) (liquid)	<u>Periodic underwater inspections</u> : Require operators to conduct periodic inspections of offshore pipelines and those in navigable waterways; within 2 years, define what constitutes an exposed underwater pipeline and what constitutes a hazard to navigation or public safety.	<u>Open</u> : A proposed rule (based on the Texas A&M University report's recommendation for a risk-based approach) is to be issued by 7/00.
113(a) (gas) 213(a) (liquid)	<u>Opportunity for state comment</u> : Provide to appropriate state officials in any state in which a pipeline facility is located notice and an opportunity to comment on any agreement proposed to be entered into by the Secretary to resolve a proceeding initiated under this section with respect to such a pipeline facility.	<u>Closed</u> : OPS provides an opportunity for state officials to comment before any agreement with a pipeline company is finalized. This is required by OPS' enforcement manual.

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**Appendix IV
OPS' Action on Statutory Requirements,
1988-2000**

Section	Statutory requirement	Status
117 (gas) 216 (liquid)	<u>Underwater abandoned pipeline facilities:</u> Identify what constitutes a hazard to navigation with respect to underwater abandoned pipeline facilities and, within 18 months, specify the manner in which operators shall report underwater abandoned pipeline facilities.	<u>Open:</u> A proposed rule was published on 8/30/99 (64 F.R. 47157). The final rule was to be published by 4/00.
206 (liquid)	<u>Low internal stress hazardous liquid pipeline facilities:</u> In exercising discretion, the Secretary shall not provide an exception to regulation for any pipeline facility solely on the basis of the fact that such a pipeline facility operates at low internal stress.	<u>Closed:</u> A final rule, issued on 7/12/94, eliminated an exemption from regulation based solely on low internal pipe stress (59 F.R. 35465). Subsequently, questions were raised about the applicability of the rule to very short segments of pipeline carrying petroleum between plant sites. A proposed rule (63 F.R. 9993, 2/27/98) and a final rule (63 F.R. 46692, 9/2/98) addressed very short plant lines.
304	<u>One-call enforcement:</u> Establish procedures to notify the Occupational Safety and Health Administration of any pipeline accident in which an excavator, by causing damage to a pipeline, may have violated the Administration's regulations.	<u>Closed:</u> OPS monitors telephone reports from pipeline operators on a daily basis. Any report of an accident involving damage by an excavator or outside force is reported to the appropriate Occupational Safety and Health Administration regional office.
306	<u>Underground utility location technologies:</u> Carry out a research and development program on these technologies.	<u>Open:</u> Funding for research on pipeline-locating and -monitoring technologies is included in OPS' fiscal year 2001 budget request as part of the agency's proposed research program. The funding is not for a specifically authorized item but is included as part of OPS' research plan for preventing excavation damage.
307	<u>Underwater abandoned pipeline facilities:</u> Undertake a study of such facilities and, within 3 years, submit a report to the Congress on the results of the study.	<u>Open:</u> The Research and Special Programs Administration analyzed the extent and nature of the hazards posed by underwater abandoned pipelines and surveyed federal policies and state activities involving abandoned pipelines in navigable waters. The collected information proved to be insufficient to fully address the issue. Therefore, the Administration issued a proposed rule (64 F.R. 47157, 8/30/99) to require the reporting of abandoned pipelines. The Administration intends to continue analyzing the hazards posed by abandoned pipelines after it issues the final rule requiring the reporting of abandoned pipelines, expected by 6/00.

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Source: For columns 1 and 2, GAO's analysis of pipeline safety statutes; for column 3, status reports from OPS.

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Table 11: Accountable Pipeline Safety and Partnership Act of 1996 (P.L. 104-304, Oct. 12, 1996)

Section	Statutory requirement	Status
49 U.S.C. 60101(b)(2) 3(b)	<u>Gathering lines</u> : Amend the requirement to define "regulated gathering line" by changing "shall" to "shall, if appropriate."	<u>Open</u> : OPS is consulting with the gas pipeline industry and gathering line operators on alternative approaches to clearly identify gathering lines. A proposed rule is expected by 7/00.
60102(a) 4(a)(2),(3)	<u>Operator qualification</u> : Change a requirement to ensure that individuals performing operations and maintenance on pipelines are properly qualified by replacing the words "test and certify" with "qualified" and define qualifications to include the ability to recognize and react appropriately to abnormal operating conditions.	<u>Closed</u> : A final rule was published on 8/27/99. Operators must have plans prepared by 4/27/01, and all workers must be qualified by 10/28/02.
60102(b) 4(b)	<u>Factors for consideration, including risk assessment and cost/benefit analysis</u> : Clarify requirements to consider risk assessment, the environment, cost-benefit analysis, and the recommendations of advisory committees when prescribing standards, as well as a general requirement that standards be practicable and designed to meet needs for safety and environmental protection.	<u>Closed</u> : OPS' cost-benefit analyses were already in compliance with most of these requirements. In 2/99, OPS published guidance for cost-benefit analyses, <i>Final Report: A Collaborative Framework for Office of Pipeline Safety Cost-Benefit Analyses</i> , developed with input from the pipeline industry and opportunity for public comment. The advisory committees are acting as "peer reviewers" for all risk assessments and cost-benefit analyses prepared by OPS to support rulemaking actions. OPS provided the advisory committees with training in risk assessment and pipeline technologies to enable the committees to fulfill their roles.
60102(b)(7) 4(b)	<u>Risk assessment</u> : Not later than 3/31/00, transmit to the Congress a report that (1) describes the implementation of the act's risk assessment requirements and (2) includes any recommendations that would make the risk assessment process a more effective means of assessing the benefits and costs associated with alternative regulatory and nonregulatory options in prescribing standards.	<u>Open</u> : OPS provided an interim report, <i>Beyond Compliance: Creating a Responsible Regulatory Environment that Promotes Excellence, Innovation, and Efficiency: A Progress Report on the Pipeline Risk Management Demonstration Program</i> , to the Congress and the public in 5/99. The agency is now clearing a final report for issuance.
60102(f)(1) 4(e)	<u>Standards on accommodating smart pigs</u> : Require new and replacement natural gas transmission and hazardous liquid pipelines to accommodate "smart pigs"; allow the extension of such standards to existing pipelines.	<u>Open</u> for certain pipelines: A final rule was published (59 F.R. 17275, 4/12/94). Notice 2 (59 F.R. 49896, 9/30/94) extended the compliance date for existing gas transmission lines and modified the requirement for offshore and rural gas transmission lines. Notice 3 (60 F.R. 7133, 2/7/95) suspended OPS' enforcement of the final rule's requirements for modifications of sections of onshore gas transmission lines and for new and existing offshore gas transmission lines. A final rule addressing a petition for reconsideration is being prepared for publication in 5/00.
60102(f)(2) 4(e)	<u>Periodic inspections</u> : Modify the requirement for the Secretary to prescribe periodic inspections of each pipeline identified in high-density and environmentally sensitive areas by inserting "if necessary, additional" after "shall prescribe."	<u>Open</u> : A proposed rule to require periodic inspections of hazardous liquid pipelines in high-consequence areas was issued on 4/24/00.

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**Appendix IV
OPS' Action on Statutory Requirements,
1988-2000**

Section	Statutory requirement	Status
60102(l) 4(f)	<u>Updating standards:</u> To the extent appropriate and practicable, update the standards incorporated by the industry that have been adopted as part of the federal pipeline safety regulatory program.	<u>Open:</u> OPS planned to issue a proposed rule in 12/99.
60102(c)(4) 4(g)	<u>Promoting public awareness:</u> (1) By 6/1/98, survey and assess certain public education and public safety programs and determine their effectiveness; (2) not later than 1 year after the survey and assessment are completed, institute a rulemaking to determine the most effective components of a public safety and education program and promulgate, if appropriate, standards implementing these components on a nationwide basis; (3) if the promulgation of such standards is not appropriate, report to the Congress the reasons for that finding.	<u>Closed:</u> A survey of damage prevention programs was completed in 1998, and a damage prevention pilot project has been completed in three states. OPS is working with the pipeline industry to evaluate existing public education programs. In 6/99, OPS "rolled out" a national promotional campaign.
60102(j)(3) 4(b)	<u>Remotely controlled valves:</u> (1) By 6/1/98, survey and assess the effectiveness of remotely controlled valves to shut off the flow of natural gas in the event of a rupture and (2) determine whether the use of remotely controlled valves is technically and economically feasible and would reduce the risks associated with a rupture; (3) within 1 year of completing the survey and assessment, if the use of valves is feasible and would reduce risks, prescribe standards for the use of these valves, including requirements for their use in densely populated areas.	<u>Open:</u> OPS published a report in 9/99 concluding that remotely controlled valves are technically, but not economically, feasible. At a public meeting on 11/4/99, OPS proposed that criteria, such as a definitive time to shut off a ruptured section in a high-consequence area, be considered. This issue will be considered further after high-consequence areas for gas transmission pipelines are defined.
60109(b) 7(b)	<u>Unusually sensitive areas:</u> Change language from "shall include" to "shall consider" under areas to be included as unusually sensitive; add drinking water and wildlife resources as considerations; and delete earthquakes and other ground movement as considerations.	<u>Open:</u> A proposed rule on the definition of unusually sensitive areas was issued (64 F.R. 73464, 12/30/99). (Comments are due on 6/27/00.)
60110(b)(4) 8(2)	<u>Excess flow valves:</u> Consider the costs of operation and maintenance in promulgating regulations requiring excess flow valves.	<u>Closed:</u> OPS adopted performance standards for excess flow valves and issued a rule requiring that customers be notified of the availability of such valves.
60126 5(a)	<u>Risk management:</u> Establish risk management demonstration projects and report on the results of such projects by 3/31/00.	<u>Open:</u> These projects are ongoing; OPS was preparing a final report for publication by 4/30/00.
60124 15(2)	<u>Biennial reports:</u> Not later than 8/15/97 and every 2 years thereafter, submit to the Congress a report on how this chapter was carried out during the 2 immediately preceding calendar years for gas and hazardous liquids.	<u>Open:</u> The first report was issued in 8/97; the next report was due in 8/99.

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**Appendix IV
OPS' Action on Statutory Requirements,
1988-2000**

Section	Statutory requirement	Status
60127(a) 16(a)	<u>Population encroachment:</u> (1) Make available to each state the land-use recommendations in the Transportation Research Board's special report entitled <i>Pipelines and Public Safety</i> (No. 219); (2) evaluate the recommendations, determine the extent to which they are being implemented, consider ways to improve their implementation, and consider other initiatives to make local planning and zoning entities more aware of issues involving the encroachment of population along pipeline rights-of-way.	<u>Open:</u> OPS sent the Transportation Research Board's report to all states. An evaluation was to be prepared and published in early 2000.
60301(nt) 17	<u>User fee assessment:</u> Within 1 year, transmit to the Congress a report analyzing the present assessment of pipeline safety user fees solely on the basis of mileage to determine whether this or another measure would be more appropriate.	<u>Closed:</u> A draft report was approved by the pipeline safety advisory committees in 5/97. A final report was prepared and submitted to Congress in 3/98.

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Source: For columns 1 and 2, GAO's analysis of pipeline safety statutes; for column 3, status reports from OPS.

Table 12: Transportation Equity Act for the 21st Century (P.L. 105-178, June 9, 1998)

Section	Statutory requirement	Status
7302(a) 49 U.S.C. 6105	<u>One-call notification systems:</u> If information is readily available, undertake a study of damage prevention practices associated with existing one-call notification systems and, within 1 year of enactment of this chapter, publish a report on the practices that are most and least successful.	<u>Closed:</u> A study of best practices to prevent damage to underground facilities, <i>Common Ground: Study of One-Call Systems and Damage Prevention Best Practices</i> , was published in 8/99. More than 160 government employees and underground facility operators contributed to the report. Follow-up action to establish a foundation for implementing the recommendations and best practices is now being established.

Source: For columns 1 and 2, GAO's analysis of pipeline safety statutes; for column 3, status reports from OPS.

Appendix V

GAO Contacts and Staff Acknowledgements

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